Part 5

Virginia Addendum 2

Grid Transformation Plan

Phase III

Smart Energy

Dominion Energy

Actions Speak Louder

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Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company owns approximately 59,700 miles of distribution lines at voltages ranging from 4 kilovolts ("kV") to 46 kV in Virginia and North Carolina.

Dominion Energy Virginia first presented its plan to transform its distribution grid ("Grid Transformation Plan," "GT Plan," or "Plan") in 2018. Since then, the Company has engaged in an iterative process to refine its Grid Transformation Plan, incorporating feedback from the State Corporation Commission of Virginia (the "Commission"), Commission Staff, and other stakeholders, to devise the best strategy to meet the overarching goals of grid transformation—facilitating the integration of distributed energy resources ("DERs") and maintaining system reliability and security.

"Phase I" of the Grid Transformation Plan focused on grid transformation projects in the years 2019, 2020, and 2021.[1] "Phase II" of the GT Plan focuses on grid transformation projects in the years 2022 and 2023. "Phase III" of the Plan now focuses on grid transformation projects in the years 2024, 2025, and 2026. The Company anticipates additional future phases of the Grid Transformation Plan to continue the objectives and efforts of grid transformation.

The Company presented its first executive summary of the Grid Transformation Plan in 2019, and presented an updated executive summary in 2021. This 2023 version updates the document to reflect industry developments supporting grid transformation, refinements to the Grid Transformation Plan, and the Company's progress with grid transformation efforts to date.

[1] The Company has referred to "Phase IA" as projects approved by the Commission in Case No. PUR-2018-00100 and "Phase IB" as projects approved by the Commission in Case No. PUR-2019-00154.

Executive Summary

Fundamental changes in the energy industry have prompted the need for utilities across the country to modernize their distribution grids. With the passage of the Grid Transformation and Security Act of 2018 ("GTSA"), the Commonwealth of Virginia recognized this need, declaring electric distribution grid transformation to be in the public interest and mandating that utilities file a plan for grid transformation. The GTSA set forth two objectives for grid transformation: (i) facilitating the integration of DERs and (ii) enhancing grid reliability and security.

In response to this need, Dominion Energy Virginia prepared a comprehensive plan to transform its distribution grid to meet the changing landscape of the energy industry while continuing to provide the reliable service that its customers expect and deserve.

In Phases I and II of the Grid Transformation Plan, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed advanced metering infrastructure ("AMI") to nearly three-quarters of its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. And the Company's new customer information platform ("CIP") is scheduled to go live in the second quarter of 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. For example, customers served by the first seven feeders targeted through the Company's mainfeeder hardening program saw on average a 50% improvement in performance on mainline sections, avoiding on average over 140,000 minutes interrupted monthly for each feeder. And the Company has facilitated the integration of DERs through, for example, the launch of two hosting capacity tools that provide guidance to customers and developers about siting clean energy installations and through its rebate program for the installation of smart charging infrastructure for electric vehicles ("EVs").

The passage of time has validated the need for the Grid Transformation Plan. In previous phases the Company discussed the policy and market developments that would accelerate the shift toward DER, including the issuance of FERC Order 2022 regarding DER aggregation for participation in regional markets and the passage of the Virginia Clean Economy Act of 2020 ("VCEA") calling for the development of significant amounts of distributed solar and energy storage and expanding opportunities for net metering in the Commonwealth. The Company has seen this shift, with an 86% increase in executed interconnection agreements for solar interconnections through the Company's queue between year-end 2021 and year-end 2022, a 59% increase in net energy metering customers, and an approximately 50% increase in customers with EVs in the Company's service territory. In addition, major weather events and physical attacks continue to show that more work is needed to achieve the objectives of grid transformation.

In Phase III, the Company seeks to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company seeks to complete the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also seeks to continue its three grid infrastructure projects approved by the Commission in prior phases—mainfeeder hardening, targeted corridor improvement, and voltage island mitigation—along with three of its previously approved grid technologies projects—a DER management system ("DERMS"), voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and to facilitate the integration of DERs. Finally, the Company seeks to continue investing in enhanced telecommunications and physical substation security, as well as investments in cyber security and customer education as needed to support other proposed projects.

Phase III also requests approval of two new projects. First, the Company proposes to deploy a new outage management system ("OMS") to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires. The new OMS is also needed to leverage the full benefits of other GT Plan investments, such as AMI, intelligent grid devices, and fault location, isolation, and service restoration ("FLISR") software. Second, the Company seeks approval of a process to evaluate energy storage systems as non-wires alternatives ("NWAs") to traditional distribution investments. This process will enable the Company to gain experience with this integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs and that may result in the integration of energy storage systems that can dynamically respond to changing grid conditions.

This document provides a guide through the need for grid modernization (Section I), the Company's distribution grid planning process (Section II), and the development of the Grid Transformation Plan (Section III). This document also provides an overview of the Plan itself (Section IV), including the accurate and reasonable cost estimates for each project based on competitive bidding processes and the quantitative and qualitative benefits of the proposed projects. The Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service.

I. Need for a Modern Distribution Grid

Electricity has become a basic need, vital to our economy, public safety, and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. As society has grown more dependent on electricity, customers expect highly reliable service. The critical need for reliable electric service became even more acute in 2020, when life for many Americans—including commerce, education, and health—shifted to the home, and the internet, because of the pandemic. While service interruptions have always been an inconvenience, the safe, reliable, and consistent grid connectivity has never been more important than it is today. With policy and climate change initiatives important to the Company and the Commonwealth, electricity should also be increasingly clean.

A. Context for Distribution Grid Transformation

The electric grid was originally designed for the one-way flow of electricity, with electricity moving from large, centralized generators through high-voltage transmission lines to the distribution system. On the distribution system, electricity flowed from the substation to the customer. While originally limited to cities, the electric power grid eventually reached even the most remote areas of the country as a result of the incentives provided in the Rural Electrification Act of 1936 for the installation of distribution systems in isolated rural areas of the United States. A comprehensive description of Dominion Energy Virginia's existing distribution grid is provided as Appendix B.

As reliance on electricity grew, focus shifted to the transmission system as vital to reliability of the electric grid as designed (*i.e.*, the one-way flow of electricity). The Northeast Blackout of 2003 drove new standards and investments into the transmission grid. The North American Electric Reliability Corporation ("NERC") became the national electric reliability organization responsible for the reliability of the transmission system, and instituted mandatory minimum standards to which transmission owners had to plan.

In the current day, focus has now shifted to DERs. The term "DER" encompasses all manner of resources, including solar and wind generation, energy storage, and EVs. As the Department of Energy's Office of Electricity noted in a 2019 report, "[m]any parts of the country are experiencing fundamental changes in customer expectations for distribution grid performance, with a large number of customers utilizing the grid to integrate DER and other new technologies or seeking a platform for market transactions."[2]

The rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution

[2] Department of Energy's Office of Electricity, MODERN DISTRIBUTION GRID (DSPX) VOLUME I: OBJECTIVE DRIVE FUNCTIONALITY at 16 (Nov. 2019) [hereinafter DOE REPORT], *available at* https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_I_v2_0.pdf.

system that was designed for the one-way flow of electricity must now accommodate the dynamic flow of electricity. In addition, the intermittent nature of some of these resources resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility, reliability, and resiliency on and control of the distribution system, the grid can transform DERs into a system resource that can be equitably managed to maximize the value of other available resources, to potentially offset the need for future "traditional" generating assets or grid upgrades, and to maintain reliable service to customers. In addition, because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs. Day to day outages as well as major weather events not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators. As the Electric Power Research Institute ("EPRI") has outlined, the distribution grid benefits DER through (i) reliability; (ii) startup power; (iii) voltage quality; (iv) efficiency; and (v) energy transaction.[3]

And throughout, severe weather and man-made events continue as a reality across the country. The value of resiliency investments in response to such events has been demonstrated both by the Company and by peer utilities, enabling timely restoration and economic recovery when damage does occur.

B. Developments Supporting Grid Transformation—2019 to 2021

Between 2019 and 2021, a number of developments occurred that support the need for grid transformation.

At the federal level, FERC issued a final rule in 2020—Order 2222—that allows for aggregation of all manner of DERs for participation in regional markets (*e.g.*, PJM). Specifically, FERC Order 2222 required each regional transmission operator to create models for DERs to aggregate and participate in their wholesale markets on a comparable level with other resources. The order defined DER broadly to include "any resource located on the distribution system," which can include "storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

In Virginia, the General Assembly accelerated its transition to a cleaner energy future with the passage of the VCEA in 2020. The VCEA called for the development of a significant amounts of DERs, including 1,100 MW of small-scale solar resources that will interconnect to the distribution grid and 2,700 MW of energy storage that may interconnect to the distribution grid. The VCEA required the Commission to adopt regulations related to the deployment of energy storage in the Commonwealth, and required those regulations to include programs and

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[3] American Public Power Association, THE VALUE OF THE GRID (Jul. 2018), *available at* https://www.publicpower.org/system/files/documents/Value%20of%20the%20Grid_1.pdf (citing EPRI, THE INTEGRATED GRID: REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES (2014)).

mechanisms to deploy energy storage, specifically including behind-the-meter incentives and non-wires alternatives programs. Many of these programs will necessarily occur at the distribution level. In addition, the VCEA expanded the opportunity for customers to participate in net metering through the installation of renewable energy resources at their distribution-connected premises and set aggressive targets for energy efficiency savings.

Throughout the country, there was support for transportation electrification. The federal administration declared its support for electric vehicles in 2021, announcing additional grant funding opportunities to encourage EV adoption. In Virginia, the General Assembly passed legislation in 2021 that encouraged transportation electrification, including rebates for the purchase of EVs and requirements for manufacturers to offer EVs for sale in Virginia. More EVs means more EV charging infrastructure connected to the distribution grid.

Aside from these developments in Virginia, advancements in other states and industry groups show that Virginia is not alone in its transition to modern distribution grids. As an example, in early 2019, the National Association of Regulatory Utility Commissioners ("NARUC") and the National Association of State Energy Officials ("NASEO") convened a task force to address the need to reimagine electricity system planning processes in a world of DERs. In its February 2021 final report, the task force leadership reemphasized the continuing relevance of the drivers that initiated its efforts: (i) improve grid reliability and resilience; (ii) optimize use of distributed and existing energy resources; (iii) avoid unnecessary costs to ratepayers; (iv) support state policy priorities; and (v) increase the transparency of grid-related investment decisions.[4]

C. Developments Supporting Grid Transformation—2021 to 2023

Additional developments supporting grid transformation efforts have occurred since the Company filed its 2021 GT Plan Document.

At the federal level, the Infrastructure Investment and Jobs Act of 2021 (the "IIJA") provides several competitive funding opportunities to incentivize energy infrastructure investment, including in the areas of grid modernization, reliability, resiliency, and flexibility. The Company intends to actively participate in as many opportunities that align with the Company's operations while providing overall net benefits to its customers. In addition, the Inflation Reduction Act of 2022 extends and adds tax incentives to promote clean energy, including incentives related to DERs.

In Virginia, Governor Youngkin, on behalf of the Virginia Department of Energy, presented a new Virginia Energy Plan in 2022 that recognized reliability as the top guiding principle, stating: "The lights must always turn on. From supporting internet connections for students to cooling homes in the summer, to powering critical data centers and state-of-the-art

[4] NARUC-NASEO Task Force on Comprehensive Electricity Planning, BLUEPRINT FOR STATE ACTION at 3 (Feb. 2021), *available at* https://pubs.naruc.org/pub/14F19AC8-155D-0A36-311F-4002BC140969.

manufacturing facilities, and to keeping a senior citizen warm in the winter, the reliability of our electricity grid is critical."[5]

Throughout the country, major events continue to show the vulnerability of the grid, including severe weather events and man-made threats to critical grid infrastructure. These events illustrate that utilities are a target. A secure, reliable, and nimble grid is necessary to respond to the events and technologies in the modern world.

D. DER Growth

The Company has seen continuous growth in DERs over the past several years. For example, for larger-scale DERs as of December 31, 2022, there are 68 interconnection requests for solar generation sites totaling 624 MW with executed interconnection agreements that are in the construction process, and 576 requests totaling 3,049 MW that are at some level of evaluation under the state interconnection process. This compares to a total of 51 utility-scale solar generation sites totaling 529 MW connected to the Company's distribution system in Virginia as of year-end 2022.

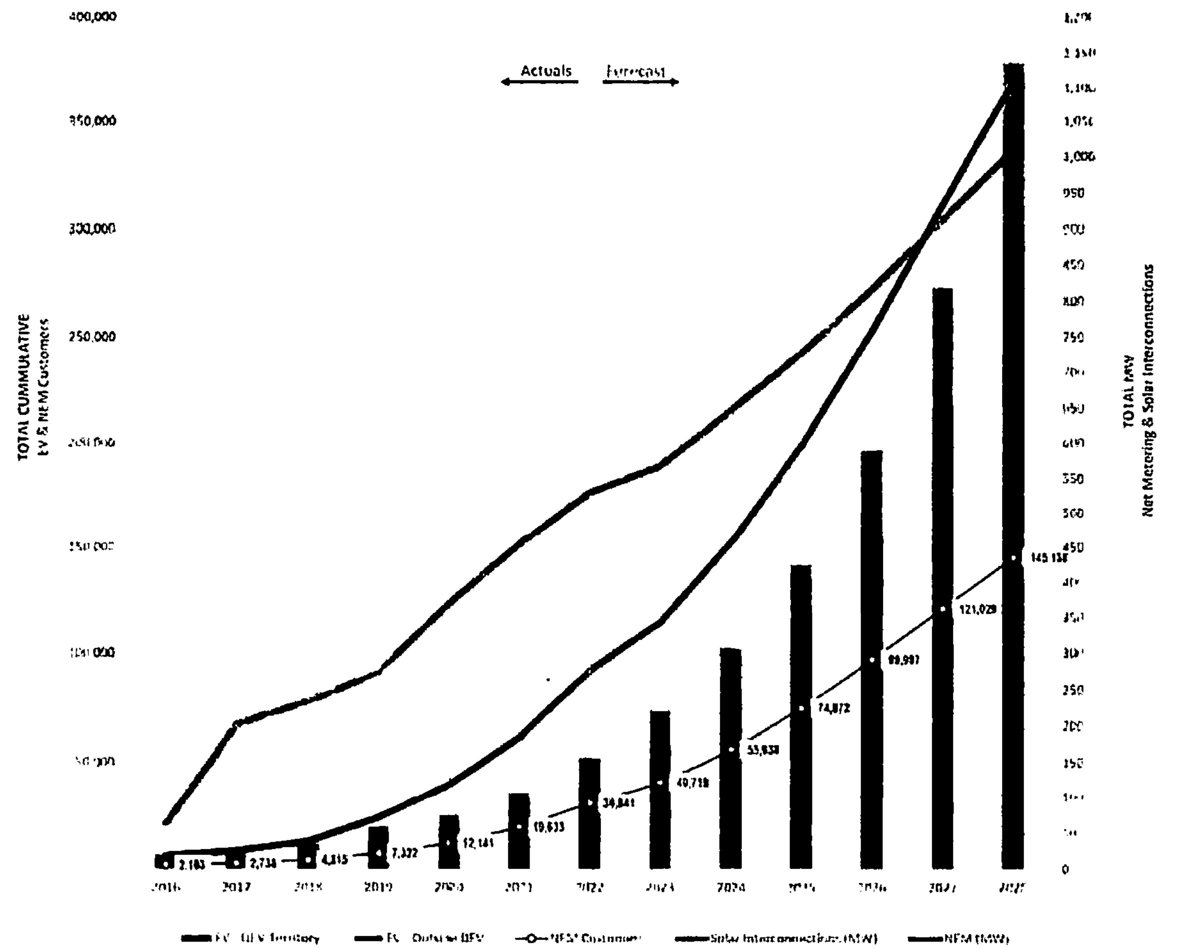
Looking at smaller DERs, the Company has seen the number of net energy metering ("NEM") customers grow from approximately 2,100 in 2016 to over 30,800 in 2022, an approximately 1400% increase in that six-year period. In 2022 alone, the Company facilitated interconnection of over 11,000 unique net metering installations. As of December 31, 2022, the Company supports over 30,800 net metering customers with a collective capacity over 275 MW at the system level. Similar growth trends can be seen related to EVs, with greater than 50,000 customers in the Company's service territory having switched to electric.

The Company expects this DER growth to continue with the market developments and supportive public policies discussed in Section I.B and I.C. Based on current forecasts, the Company expects both solar interconnections on the distribution grid and net energy metering installations to total more than 2,100 MW, and projects over 300,000 customers switching to EVs.

Figure 1 shows the actual growth in DERs between 2016 and 2022, as well as the forecasted growth in DERs for the next five years.

[5] Virginia Department of Energy, 2022 VIRGINIA ENERGY PLAN, *available at* https://energy.virginia.gov/energy-efficiency/documents/2022_Virginia_Energy_Plan.pdf.

Figure 1: DER Growth in Dominion Energy Virginia Service Territory



Propagated in an arbitrary manner, DERs can disrupt grid power quality and reliability. Yet the investments outlined in the Grid Transformation Plan combined with the evolution of the Company's integrated distribution planning process seek to ensure that any potential adverse impacts will not occur. Specifically, the completed and planned GT Plan investments to increase visibility, reliability, and resiliency on and control of the distribution system enables the Company to transform DERs into system resources. In addition, combining the data generated from these investments with new modeling methodologies and advanced analytics will enable the Company to generate detailed forecasts for new DERs and load—along with simulations of the potential impacts of new DERs and load on the grid—to plan for the future needs of the grid and to address those needs before adverse impacts occur.

E. Value of a Transformed Distribution Grid to Customers

Foundational investments to transform the distribution grid will allow the Company to use the distribution system differently than it has historically, all for the benefit of customers.

Transformational investments in AMI, the CIP, intelligent grid devices, and automated control systems will enable the Company to improve operations (*e.g.*, reduced truck rolls; more predictive and efficient maintenance; increased visibility and control; optimized use of DERs), better forecast load shape, and predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs; enabling overall savings and cost management of demand-side management ("DSM") programs), resulting in a better, more informed customer experience. This value of a transformed distribution grid can be seen from the view of different types of customers.

Prior to grid transformation, all customers had to take specific action to report outages and then wait for the Company to deploy resources to bring the power back on. With transformational investments in AMI, CIP, intelligent grid devices, automated control systems (*e.g.*, OMS, FLISR), and resilience, customers will experience fewer outages and will not need to take action to report outages when they do occur. Instead, when outages do occur on the more connected and resilient grid, the outages reported through smart meters and other intelligent grid devices will prompt the dynamic system to automatically restore power to as many customers as possible, narrowing the scope of the outage and focusing effort on issues that require manual intervention. Additionally, grid visibility provided by the transformed grid will allow customers to receive proactive outage and restoration alerts—and more accurate information on expected restoration times, including detailed outage maps—allowing the fewer customers that are impacted to better adapt to the situation.

Prior to grid transformation, most residential customers received monthly energy usage data at a summary level through their bills. With transformational investments in AMI and the CIP, all residential customers can receive detailed interval energy usage data through convenient communication channels. The corresponding education will inform customers on how to take control of and manage their energy usage, if desired. These customers will also have the opportunity to participate in time-varying rates and innovative DSM programs that these investments will enable the Company to broadly offer. Such rate options and DSM programs can prompt behavioral changes that benefit customers through bill savings and reduced system costs. Indeed, customer have already begun to take advantage of these opportunities, with 10,000 customers enrolled in the Company's experimental time-of-use rate, the Off-Peak Plan (*i.e.*, Schedule 1G), and more than 14,000 email addresses added as a convenient communication channel for customers. Further, with transformational investments in voltage optimization, informed by the data from AMI and intelligent grid devices, most customers will see lower energy consumption without a noticeable difference in service level because of the more precise voltage control settings.

Prior to grid transformation, multi-family complex customers (*e.g.*, apartment complexes) had meters that limited the efficiency of the move-in / move-out process, a process that happens more frequently than for single-family homes. With transformational investments in AMI and the CIP, customers can change accounts the same day, leading to more efficient relocation, easier owner / tenant billing, and lower costs.

Prior to grid transformation, DER net metering customers had to engage in a largely manual application process, and then wait for a meter exchange. The meter exchange process alone could take up to 10 business days to schedule and complete, leading to potential interconnection delays for the customer. With transformational investments in AMI, CIP, intelligent grid devices, a DER management system ("DERMS"), and resilience, DER customers will (i) experience a much faster and seamless interconnection process, (ii) will no longer need a meter exchange, and (iii) will receive detailed information on how their DERs interact with the grid. Further, customers will maximize the value of their DERs through the connection with a resilient grid, and through opportunities to offer their DERs into programs that provide grid support or other functions. In addition, transformational grid investments have enabled a hosting capacity map that allows customers, and even localities, to evaluate optimal locations to interconnect DERs—a map that will continue to become more dynamic as additional AMI and intelligent grid devices are added to improve grid visibility. By empowering customers with the information to optimally locate DER, customers can realize reduced interconnection costs and potentially contribute to the deferral of other system investments.

Prior to grid transformation, the majority of EV customers did not have attractive options to encourage them to charge their vehicles during times when the demand for electricity is low. With transformational investments in AMI, CIP, and smart charging infrastructure, EV customers have access to more innovative programs and advanced rate options, such as the Company's Off-Peak Plan that can lead to bill savings and reduced system costs.

Prior to grid transformation, business customers were subject to sudden voltage fluctuations when outage events occurred on the distribution grid. Even when a customer did not experience a sustained outage, these voltage fluctuations have the potential to impact operational processes and facility production. The intermittency and changing power flows related to renewable generation introduce new dynamics to grid operation that, if not managed properly, have the potential to similarly impact these customers. Transformational investments in reliability and resiliency will eliminate certain outage events and the associated voltage fluctuations that ripple across the distribution grid, while also ensuring power is restored more quickly when it does go out. With transformational investments in AMI, intelligent grid devices, and automated control systems, the Company will have the situational awareness and control capabilities to manage grid operation so business customers can rely on voltage stability to ensure minimal disruption to their operations.

Prior to grid transformation, vital community resources are more dependent on grid reliability than ever before. Health and safety services, such as hospitals, water, and emergency services, carry the highest priority day-to-day and in a restoration event, closely followed by commerce and education, including internet services for home and work. More grid availability translates to availability for DER to contribute to system resources in the form of capacity factor. With transformational investments in resilient grid architecture, customers will have confidence that their growing reliance will be served.

Dominion Energy Virginia values the experience of its customers and believes that the Grid Transformation Plan will enable the Company to meet their changing needs and expectations.

II. Distribution Grid Planning

The fundamental changes in the energy industry discussed in Section I have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs.

In 2019, the Company presented a white paper that provided a conceptual first-look at its transition toward integrated distribution planning ("IDP"). The Company defines integrated distribution planning as a consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that the one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and stated its intention to present that roadmap in 2023. The Company's current IDP roadmap is attached as Appendix C to this GT Plan Document (the "2023 IDP Roadmap" or the "Roadmap"). The Roadmap presents tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 2 provides a visual representation of the Roadmap.

Part 2

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

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Case Number (if already assigned)	PUR-2023-00066
Case Name (if known)	Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
Document Type	APLA
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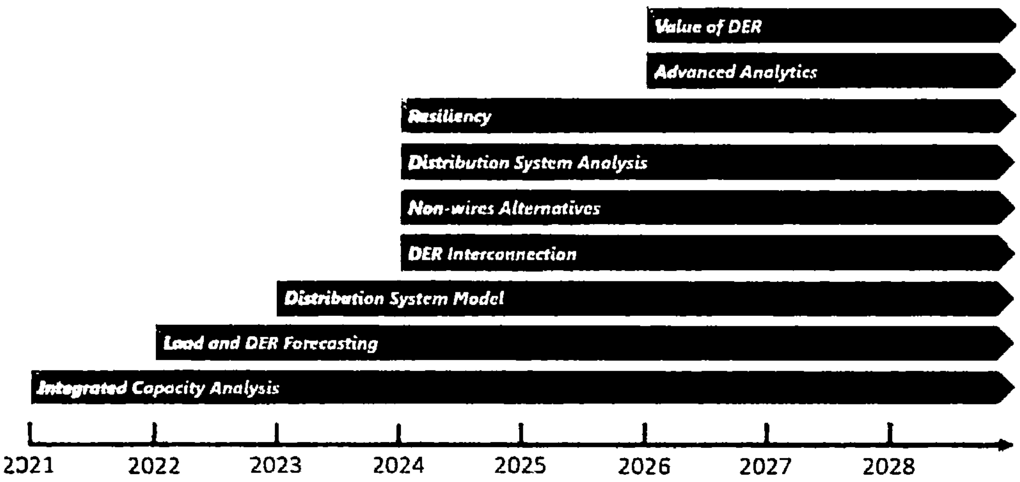
Total Number of Pages	54
Submission ID	27439
eFiling Date Stamp	5/1/2023 3:15:28PM

Figure 2: 2023 IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the 2023 IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components.

III. Development of Grid Transformation Plan

The Company has engaged in an iterative process to develop the Grid Transformation Plan presented in this document. Guided by the policy objectives of the Commonwealth to facilitate the integration of DER and enhance distribution grid reliability and security, the Company incorporated its experience-based knowledge with input from customers and stakeholders; with lessons from the experiences of peer utilities; and with guidance provided by the Commission in prior orders.

A. Internal Process

The Company consistently tracks developments in the energy industry and challenges for its distribution system. The Company collaborates with its peer utilities and learns from their experiences. The Company keeps current with information published by various industry groups and has engaged with these industry groups to gain additional knowledge and perspective. The Company also continues to engage an industry expert, West Monroe Partners, as a knowledgeable partner in the development and implementation of a plan to modernize the distribution grid. The Company intentionally tests certain components of the GT Plan on a smaller scale prior to full scale deployment, such as AMI and mainfeeder hardening. And the Company continuously incorporates lessons learned from prior GT Plan investments into its strategy for deployment of GT Plan investments into the future. All of this knowledge coalesced to create the framework for and to ensure prudent implementation of the Grid Transformation Plan.

B. Customer Engagement

Dominion Energy Virginia strives to meet its customers' energy needs while providing a seamless customer experience. To that end, the Company frequently seeks feedback from its customers in various forms and forums. The Company has also sought specific feedback to assist in the development of the Grid Transformation Plan. The Company intends to continue this customer engagement to assess the priorities included in the GT Plan.

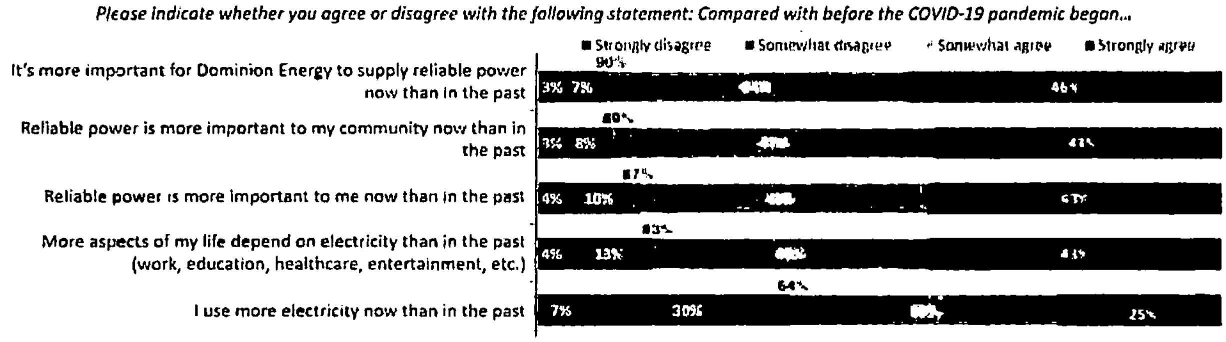
The Company receives customer feedback on a daily basis. The Company strives not only to quickly and fairly resolve any customer issue, but also to identify trends and possible process improvements. The Company will continue to engage with customers on an ongoing basis in its efforts to meet customer needs and expectations.

In 2019, the Company presented the results of a survey conducted by Maslansky + Partners ("Maslansky") to evaluate customer priorities related to the Grid Transformation Plan. Maslansky based this effort on a nationwide survey fielded by Edison Electric Institute ("EEI") on the "Voice of the Customer," and, where applicable, compared the results of the Virginia survey and the national study. In 2021, the Company contracted with an external third-party to conduct enterprise-wide and Virginia-based research to evaluate customer priorities.

To further understand and confirm customer priorities, in 2023, the Company engaged Maslansky to conduct an updated survey to evaluate customer priorities related to the Grid

Transformation Plan, with a focus on customer expectations around reliability in light of the pandemic. The survey indicated that customers report the value of reliable energy has increased since the pandemic, with 90% of customers surveyed agreeing that "it's more important for Dominion Energy to supply reliable power now than in the past." Figure 3 shows the results of this survey related to the importance of and dependence on reliable energy.

Figure 3: Maslansky Findings on Importance of and Dependence on Reliable Energy



C. Stakeholder Engagement

In furtherance and development of the Company's GT Plan and related initiatives, the Company began a series of stakeholder sessions in mid-2019 to inform and develop goals for a modern grid and the customer experience.

Ahead of its Grid Transformation Plan filing in 2019, the Company engaged an industry expert, Navigant, to facilitate an external stakeholder process. Attendees included a range of stakeholders with varying interests, from environmental advocates to municipality representatives to low-income advocates. Commission Staff also attended the stakeholder process. Navigant facilitated a series of workshops that guided the conversation on the stakeholders' vision and objectives for grid transformation. Through collaborative conversations, a group of the stakeholders identified four goals for grid transformation:

- **Optionality**: Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.
- **Sustainability**: Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.
- **Resiliency**: Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.
- **Affordability**: Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.

Using these goals as a guide, Navigant led an exercise for stakeholder groups to prioritize grid capabilities that any plan for grid transformation should enable. Consistent across all stakeholder groups were investments that enabled two capabilities: (i) integrate and optimize DERs and (ii) provide relevant, data-enabled options that enable customers to meet their goals. In addition, highly prioritized by at least one stakeholder group were investments that enabled the following capabilities: (iii) increase monitoring and visibility; (iv) accommodate two-way power flows; (v) enable voltage monitoring and control, supporting load management and peak shifting; (vi) simplify interconnection for residential customers; and (vii) harden for resiliency and security.

Ahead of the Grid Transformation Plan filing in 2021, the Company re-convened stakeholders to provide an update and opportunity for feedback on various GT Plan components over three sessions. The first session focused on AMI, the CIP, and other customer-related programs such as the Company's Schedule 1G (marketed as the Off-Peak Plan). The second session focused on the Company's approved Smart Charging Infrastructure Pilot Program and other electrification initiatives. The third session focused on the Company's proposed intelligent grid device deployment and DERMS, and how the GT Plan more generally supports the objectives of the VCEA. Attendees at these sessions included a range of stakeholders with varying interests, from environmental advocates to state agency representatives to low-income advocates. Commission Staff also attended the stakeholder process.

Ahead of this 2023 Grid Transformation Plan filing, the Company again re-convened stakeholders to provide an update and opportunity for feedback. The Company provided status updates on specific projects of interest from Phases I and II, including AMI, the CIP, targeted corridor improvement, mainfeeder hardening, substation technology deployment, intelligent grid devices, and physical security. The Company also provided a preview of projects for which it planned to seek approval in Phase III, including the NWA Program. The Company invited to this session Commission Staff, respondents from prior GT Plan proceedings, and other stakeholders with varying interests, including state agency representatives and low-income advocates.

The Company intends to continue engagement with stakeholders as its grid transformation efforts proceed.

D. Environmental Justice Evaluation

Under the Virginia Environmental Justice Act ("VEJA"), environmental justice is defined as the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The primary tenets of the VEJA—fair treatment and meaningful involvement—were not created anew in the Commonwealth, but instead stand and build upon existing, governmental environmental justice policies stemming back to Executive Order 12898 issued by President Clinton in 1994. This Executive Order focused on disproportionately high and adverse human health or environmental effects, including high risks from environmental hazards and impacts on populations relying on subsistence lifestyles, of federal agencies' actions on minority populations and low-income populations.[6]

[6] Executive Order 12,898 §§ 1-101, 3-301, 4-401 (Feb. 16, 1994), *available at* https://www.archives.gov/files/federal-register/executive-orders/pdf/12898.pdf.

Like its federal predecessor, under the VEJA, "fair treatment" focuses on the negative and adverse environmental impacts of a project, and is defined to mean "the equitable consideration of all people whereby no group of people bears a disproportionate share of any negative environmental consequence resulting from operations, programs, or policies." Similarly, "meaningful involvement" under the VEJA means "the requirements that (i) affected and vulnerable community residents have access and opportunities to participate in the full cycle of the decision-making process about a proposed activity that will affect their environment or health and (ii) decision makers will seek out and consider such participation, allowing the views and perspectives of community residents to shape and influence the decision." The VEJA defines "environment" broadly to mean "the natural, cultural, social, economic, and political assets or components of a community."

Dominion Energy Virginia is dedicated to meeting environmental justice expectations of fair treatment and meaningful involvement by being inclusive, understanding, and dedicated to finding solutions, and by effectively communicating with its customers and neighbors. The Company adopted an environmental justice policy in 2018 through which it committed to hearing, fully considering, and responding to the concerns of all stakeholders. Consistent with the VEJA, this commitment includes ensuring that a voice in decisions about siting and operating energy infrastructure is given to all people and communities. Communities should have ready access to accurate information and a meaningful voice in the project development process. The Company has pledged to be a positive catalyst in its communities.

Generally, when conducting an environmental justice review, one evaluates: the type of activity (*e.g.*, a project or program at issue); where it will occur; what type of environmental impacts are likely; if any impacts, are they negative or adverse; and, whether there are environmental justice communities (as that term is defined by the VEJA) that might suffer the negative or adverse environmental impacts of the proposed activity. These factors are consistent with the VEJA, U.S. Environmental Protection Agency guidance, and currently accepted best practices. The VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. For example, the definition of "community of color" focuses on "any geographically distinct area," and the definition of "low-income community" focuses on "any census block group."

The outcome of one or more of the inquiries in a typical environmental justice review may result in a finding that no environmental justice concerns exist. For example, a proposed project to upgrade a computer system may not have an environmental impact on any community, let alone an environmental justice community. As noted above, the VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. Thus, in this example, because a discrete environmental justice community is not at issue, the environmental justice review under the VEJA would be at an end. Assuming there is an environmental justice community that might suffer negative environmental impacts of the proposed activity, then an analysis is done to determine whether that community would bear a disproportionate share of such impacts. As discussed below, in preparing the Grid Transformation Plan, Dominion Energy Virginia evaluated each proposed project to determine whether any environmental justice concerns exist.

The Grid Transformation Plan includes multiple projects, some of which will require work in communities throughout the Company's service territory, and some that will not. While all of the proposed work in this Plan is intended to benefit these communities, and all customers broadly, as discussed in Section IV.B, the Company remains committed to ensuring environmental justice. Five of the fourteen grid transformation projects proposed for Phase III do not have a physical component that would cause any environmental consequence—the CIP, DERMS, OMS, cyber security, and customer education. In addition, the Storage NWA Program will not have a physical component unless a specific energy storage resource is selected under the proposed process. The remaining eight Phase III grid transformation projects will require at least some work in communities. The Company proposes to deploy some of these projects broadly, and eventually in nearly every community it serves, such as the system-wide deployment of AMI and voltage optimization enablement. Other projects will focus on mitigating reliability, resiliency, and security risks in select areas, such as voltage island mitigation, substation technology deployment, and physical security.

The Company has engaged a third-party consultant to evaluate the eight Phase III grid transformation projects that will require at least some work in communities, and will use the results of this evaluation to inform its environmental justice strategy as it relates to the GT Plan. As discussed, in Section III.C, the Company has engaged in outreach with a number of stakeholders and stakeholders' representative groups regarding the GT Plan, and otherwise plans to continue with additional outreach and meaningful involvement activities as appropriate.

IV. Grid Transformation Plan

Virginia Code § 56-585.1 A 6 requires that any plan for electric distribution grid transformation projects "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security." Based on the development process described in Section III, the Company presents a comprehensive plan designed to achieve all of the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner.

The Grid Transformation Plan includes six core components: (i) AMI; (ii) CIP; (iii) grid improvements within two categories, grid infrastructure and grid technologies; (iv) transportation electrification; (v) security; and (vi) telecommunications infrastructure. Certain components, such as grid improvements, consist of multiple electric distribution grid transformation projects. The Plan also incorporates customer education related to the Company's grid transformation efforts generally, and to specific projects.

A. Interrelated Nature of Projects

The Company developed its Grid Transformation Plan as an integrated package of projects that work together for the benefit of customers to achieve the objectives of grid transformation—to facilitate the integration of DERs and to improve grid reliability and security. While some projects may provide benefits standing alone, the benefits increase exponentially when paired with the capabilities of other projects. The Company focused on the synergy between capabilities to ensure that it would not miss opportunities to benefit its customers. Some examples of these synergies follow, though they do not represent a comprehensive list.

The Company could have deployed a new CIP to replace its aging infrastructure and use it to manage customer billing. But the new CIP will transform the customer experience when it can use the data from AMI to provide customers detailed and timely education about their energy consumption, empowering customers to manage their energy usage to suit their individual goals.

The Company can (and did) publish a static hosting capacity tool with data obtained from existing sources, and refresh that tool quarterly. But the distribution grid is now a dynamic system that changes daily as any number and type of DERs are installed along feeders. When fed by the data from AMI and intelligent grid devices, the hosting capacity tool can refresh more frequently with the most up-to-date information, providing customers, localities, and developers with the tools to make the right decisions for them on siting DERs.

The Company could have deployed DERMS to manage the growing population of DERs. But DERMS will best optimize use of DERs for grid support when informed by the data collected from AMI and intelligent grid devices over a secure telecommunications network. Every additional data element that DERMS collects helps it to become smarter—thus providing grid operators additional tools—in assessing real-time grid constraints and managing DERs accordingly. Further, investments in reliability and resiliency will ensure that these DERs are available to provide grid support on which the system can rely.

The Company could have deployed intelligent grid devices to provide situational awareness on the distribution grid. These devices alone would support many other grid transformation projects with the data collected, as described in the examples above. But when paired with the FLISR control system, the Company will unlock significant reliability improvements for customers at a small incremental cost, leading to faster overall system restoration time.

Finally, the Company could deploy OMS to replace its aging infrastructure and to manage outages on its modern distribution system. But when fed by the data from AMI and intelligent grid devices and when paired with the functionality of FLISR, a new OMS can assess field conditions to better identify and analyze outage events.

B. Projects

The sections that follow provide an overview of each project incorporated into the Grid Transformation Plan and summarize the need for the specific project, the deployment timeline, the alternatives considered, and the benefits. Refer to Appendix B as needed for context, which provides a description of the existing distribution grid. Finally, each section provides an overview of the Company's progress to date on the project, if applicable. These sections are intended to provide a high-level overview only; more information on each project is provided by the sponsoring Company witness.

1. Advanced Metering Infrastructure

Dominion Energy Virginia plans to fully deploy AMI across the service territory. Through this technology, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters.

- Need. Modernize the distribution grid by digitally gathering customer energy usage data in specific increments and other premises-level data; replace aging AMR meters and associated equipment and systems.
- Deployment Timeline. Full deployment over six-year period of 2019 to 2024.
- Alternatives Considered. No alternatives considered from a general metering technology perspective, as the Company does not consider AMR meters as a viable metering solution on a modern distribution grid. Prior to deployment of AMI, considered alternative systems, vendors, and deployment timeline. Now that deployment is near complete, no alternative systems considered. The Company continues to consider new, compatible smart meters as they are developed and released to the market.
- Benefits. Advanced time-varying rates; targeted DSM programs; reduced components of the cost of service; enhanced grid operations; enhanced DER integration; avoided capital maintenance investments.
- Phase III Request. Deploy approximately 195,000 smart meters and associated infrastructure; optimize the AMI mesh network.
- Progress to Date. Installed approximately 1.95 million smart meters as of December 31, 2022; avoided almost 772,000 truck rolls in 2022 alone; reduced bad debt expense in areas where AMI has been deployed; reduced "found ons" by approximately 70% in

areas where AMI has been deployed; launched Schedule 1G for customers in areas where AMI has been deployed, with the pilot reaching its participant cap in less than one year.

2. Customer Information Platform

Dominion Energy Virginia proposes to implement a new CIP that will replace existing systems that support different aspects of the customer experience, including aging and outdated systems. As part of this project, the Company also proposes to complete a bill redesign to make it more understandable and easy to read.

- Need. Modernize the customer experience; replace antiquated customer information system.
- Deployment Timeline. Full deployment of all four projects by 2024; Core Project to replace existing systems live in second quarter of 2023.
- Alternatives Considered. Prior to Phase I, considered the alternative of a patchwork of applications and manual processes. Now that deployment of the Core Project is near complete, no alternatives considered. Only alternative to the bill redesign project is to not complete the project.
- Benefits. Modernized customer relationship; advanced time-varying rates, DSM programs, and other customer offerings at scale; reduced manual workarounds; avoided capital maintenance investments; improved customer satisfaction.
- Phase III Request. Finalize deployment of CIP by completing the customer bill redesign.
- Progress to Date. Launched Outage Center app in November 2019, with more than 490,000 downloads since its launch as of December 31, 2022; launched notification Preferences in April 2020; Core Project scheduled to go live in the second quarter of 2023.

3. Grid Infrastructure

Within the category of grid infrastructure, the Company proposes: (a) hardening mainfeeders; (b) deploying targeted corridor improvement activities; and (c) mitigating voltage islands.

a. Mainfeeder Hardening

Dominion Energy Virginia proposes to complete hardening work (*i.e.*, physically strengthening infrastructure; improving distribution system architecture and connectivity) on a targeted population of mainfeeders.

- Need. Improve reliability on the worst performing mainfeeders.
- Deployment Timeline. Harden 195 mainfeeders through completion of the GT Plan.
- Alternatives Considered. Considered addressing issues on the identified mainfeeders reactively as outages occur rather than proactively, hampering efforts to improve reliability for these customers. Considered alternative solutions and identified the appropriate hardening solution for each mainfeeder based on detailed engineering and design.

- Benefits. Improved reliability and resiliency; faster recovery after severe weather events.
- Phase III Request. Harden a total of 111 mainfeeders, targeting 44 in 2022 and 2023 and an additional 67 in the years 2024, 2025, and 2026.
- Progress to Date. Completed hardening work on 17 mainfeeders as of December 31, 2022.

b. Targeted Corridor Improvement

Dominion Energy Virginia proposes several vegetation management programs to improve grid reliability and resiliency while minimizing environmental impacts.

- Need. Improve accessibility to right-of-way; remove risk related to ash trees, hazard trees, and tree overhang.
- Deployment Timeline. Ash tree remediation completed by end of 2024; ground floor maintenance completed by end of 2027; hazard tree pilot program completed by end of 2024; tree overhang pilot program completed by 2026.
- Alternatives Considered. Considered addressing ash trees, ground floor growth, and hazard trees reactively rather than proactively, potentially affecting reliability and resiliency, increasing costs for restoration and maintenance work, and requiring higher cost options for ash tree removal. Considered different scopes for pilot programs.
- Benefits. Improved reliability and resiliency; improved access to right-of-way.
- Phase III Request. Continue ash tree mitigation and ground floor maintenance programs; pilot program focused on surveying and removal of hazard trees; pilot program focused on removal of tree overhang.
- Progress to Date. Removed over 16,900 ash trees; treated over 22,300 miles of right-of-way as of December 31, 2022.

c. Voltage Island Mitigation

Dominion Energy Virginia proposes to mitigate voltage islands, which are single substation transformers that serve a population of customers without the support of available load transfer capability within the substation or through field tie switches to adjacent feeders.

- Need. Mitigate risk of an extended outage for customers served by voltage islands if the single substation transformer fails.
- Deployment Timeline. Address 19 voltage islands through completion of the GT Plan.
- Alternatives Considered. Considered not mitigating the risk of extended outages for customer served by voltage islands. Considered alternate solutions and identified the appropriate solution for each voltage island.
- Benefits. Reduced risk of extended outages; improved reliability.
- Phase III Request. Address six voltage islands.
- Progress to Date. Addressed three voltage islands as of December 31, 2022.

4. Grid Technologies

Within the category of grid technologies, the Company proposes: (a) installing intelligent grid devices; (b) deploying FLISR; (c) implementing a DERMS; (d) conducting and publishing hosting capacity analysis; (e) implementing an enterprise asset management system ("EAMS"); (f) installing a new OMS; (g) enabling voltage optimization through infrastructure upgrades; (h) deploying modern technologies at substations; (i) establishing a program to seek energy storage systems as a non-wires alternative solution at identified locations on the distribution grid; and (j) demonstrating microgrid capabilities at the Locks Campus.

a. Intelligent Grid Devices

Dominion Energy Virginia proposes to install intelligent grid devices ("IGDs") to provide the data and control necessary to restore power and manage distribution grid voltages and power flows in a system with increasing penetrations of DERs.

- <u>Need.</u> Monitor the distribution grid; remotely control the distribution grid to restore power and address power quality issues created by DERs.
- <u>Deployment Timeline.</u> Deploy IGDs on 685 mainfeeders or feeder segments through completion of the GT Plan.
- <u>Alternatives Considered.</u> Considered different equipment and vendor options to achieve the needed situational awareness and grid control functionality. Considered alternative deployment options in terms of the number and location of devices on each feeder based on detailed engineering and design, and good utility practice.
- <u>Benefits.</u> Increased data about the distribution grid, which enables remote monitoring and control of grid operations; enhanced integrated distribution planning; improved hosting capacity tool; improved reliability.
- <u>Phase III Request.</u> None.
- <u>Progress to Date.</u> Deployed 91 IGDs on 24 feeders as of December 31, 2022.

b. FLISR

Dominion Energy Virginia proposes to install a distribution automation system called FLISR, which stands for fault location, isolation, and service restoration, to leverage the capabilities of intelligent grid devices to improve reliability.

- <u>Need.</u> Improve reliability; leverage the full capabilities of intelligent grid devices.
- <u>Deployment Timeline.</u> Upgrades integrated into ADMS by the third quarter of 2023.
- <u>Alternatives Considered.</u> Considered not leveraging the capabilities of IGDs to improve customer reliability through FLISR; rejected alternative because the incremental cost of FLISR software is justified by the reliability improvements for customers. Considered alternative software vendors.
- <u>Benefits.</u> Improved reliability; reduced outage-related O&M expenses; improved customer satisfaction.
- <u>Phase III Request.</u> None.
- <u>Progress to Date.</u> Began software installation and configuration

c. DER Management System

Dominion Energy Virginia proposes to deploy DERMS to monitor, control, and optimize increasing levels of DERs on the Company's system to maintain a safe and reliable grid.

- Need. Manage increasing volumes of DERs.
- Deployment Timeline. Complete initial installation by 2024; complete additional integrations by 2026.
- Alternatives Considered. Considered using a patchwork of manual processes to manage the increased volumes of DERs of various sizes and types; rejected alternative because of the objectives of FERC Order 2222, the complexity of operating in this manner, and the risk to system reliability and security as penetration increases. Considered alternative software vendors.
- Benefits. Enhanced monitoring and optimization of DERs; enabled customer programs at scale, such as EV managed charging and vehicle-to-grid; facilitated non-wires alternatives.
- Phase III Request. Continue to install DERMS.
- Progress to Date. Selected vendor for the DERMS platform.

d. Hosting Capacity Analysis

Dominion Energy Virginia proposes to complete and publish a hosting capacity analysis, and to refresh this analysis on a regular basis.

- Need. Provide customers, localities, and developers guidance about which sections of the distribution system may be more suitable to site new DERs.
- Deployment Timeline. Initial hosting capacity tool launched January 2021; additional capabilities implemented in 2022 for smaller generation projects.
- Alternatives Considered. Considered not providing this information to customers and developers, increasing their risk related to siting DERs in terms of costs to interconnect.
- Benefits. Increased information for customers, localities, and developers about how DERs can be placed at each point on the distribution grid without causing voltage or loading problems; increased proliferation of DERs.
- Phase III Request. None.
- Progress to Date. Launched a utility-scale hosting capacity tool in January 2021 and a behind-the-meter-scale hosting capacity tool in April 2022, available at https://www.dominionenergy.com/projects-and-facilities/electric-projects/energy-grid-transformation/hosting-capacity-tool; over 2,600 unique page views as of December 31, 2022.

e. Enterprise Asset Management System

Dominion Energy Virginia proposes to implement EAMS to improve its asset management practices by assessing the health and performance of physical distribution grid assets and to drive predictive maintenance activities.

- Need. Improve asset management practices.
- Deployment Timeline. System deployed in 2024.
- Alternatives Considered. Considered continued use of a patchwork of manual processes and isolated data system to manage distribution grid assets; rejected alternative because it would result in repeated reactive tactics and the inability to develop proactive and predictive strategies to mitigate equipment-related risk and realize asset life optimization opportunities.
- Benefits. Improved capabilities and strategies for managing the procurement, deployment, maintenance, and retirement of distribution equipment and devices.
- Phase III Request. None.
- Progress to Date. Selected vendors to support implementation of EAMS.

f. Outage Management System

Dominion Energy Virginia proposes to install a new OMS to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires.

- Need. Replace outdated operating system; leverage the full benefits of other GT Plan investments; modernize customer engagement.
- Deployment Timeline. Complete deployment by the fourth quarter of 2025.
- Alternatives Considered. Considered alternatives related to the timing of installation. Considered alternative vendors.
- Benefits. Restoration efficiency and productivity; improved customer experience.
- Phase III Request. Install OMS.
- Progress to Date. Not applicable.

g. Voltage Optimization Enablement

Dominion Energy Virginia proposes to make the improvements necessary to enable voltage optimization on the feeders where AMI has been installed.

- Need. Enable voltage optimization to achieve energy savings for customers by performing the necessary infrastructure improvements, as identified by data from AMI.
- Deployment Timeline. Complete infrastructure improvements that support implementing a 1% energy savings through voltage optimization capability, estimated at approximately 56,000 customer premises to be addressed.
- Alternatives Considered. Considered lesser percentage voltage reductions to target, which affects the necessary infrastructure improvements and resulting energy savings.

- Benefits. Broadly-enabled voltage optimization, which will result in generally lower voltage control settings leading to lower energy consumption for most customers without a noticeable difference in service level.
- Phase III Request. Complete infrastructure improvement to address approximately 28,000 customer premises.
- Progress to Date. As of December 31, 2022, completed 145 voltage optimization enablement service premises. Received approval of voltage optimization software deployment in January 2023.

h. Substation Technology Deployment

Dominion Energy Virginia proposes to modernize certain distribution substations by upgrading electromechanical relays; deploying substation communication protocol and power quality monitoring equipment; and piloting advanced substation technology.

- Need. Integrate DERs; improve reliability, power quality, and safety; study advanced substation technology.
- Deployment Timeline. Modernize 44 substations through completion of the GT Plan; deploy advanced substation technology as appropriate based on outcome of pilots.
- Alternatives Considered. Considered addressing substation equipment issues reactively rather than proactively; rejected alternative because it could result in an inability to effectively integrate DERs or feeder automation, such as FLISR, on the associated feeders.
- Benefits. Support for the integration of DERs while maintaining voltage stability; improved reliability, power quality, and resilience of the distribution grid; improved visibility and control; enhanced understanding of advanced substation technology.
- Phase III Request. Modernize 20 substations.
- Progress to Date. Began design, procurement, permitting, and construction at targeted substations. Installed 75 power quality monitors as of December 31, 2022.

i. NWA Program

Dominion Energy Virginia proposes to implement a non-wires alternative program to identify opportunities in which a traditional infrastructure investment may be deferred or avoided by investing in an alternative solution, with initial focus on energy storage systems.

- Need. Gain experience with integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs. Address requirement from the VCEA related to the deployment of energy storage.
- Deployment Timeline. First RFP for NWA solutions issued in 2024.
- Alternatives Considered. Considered alternative timelines for implementing NWA Program. Considered seeking NWA solutions in addition to energy storage.
- Benefits. Address VCEA requirement that the deployment of energy storage involved non-wires alternatives program; experience with NWAs; potential deployment of energy storage to meet VCEA development targets, and associated experience with energy storage; potential deferment of traditional capital investments.

- Phase III Request. Approval of process used to solicit and, if selected, implement NWA solutions.
- Progress to Date. Not applicable.

j. Locks Campus Microgrid

Dominion Energy Virginia proposes to study a new technology—microgrids—by installing one at its Locks Campus near Petersburg, Virginia.

- Need. Obtain experience with microgrids.
- Deployment Timeline. Construction completed by third quarter of 2024.
- Alternatives Considered. Not obtaining experience with microgrids.
- Benefits. Enhanced understanding of microgrids from real-world data and testing of DER grid support and islanding capabilities.
- Phase III Request. None.
- Progress to Date. Awarded engineering, procurement, and construction contract; began field construction.

5. Transportation Electrification

Dominion Energy Virginia plans to offer rebates and install a limited number of Company-owned charging stations through its Smart Charging Infrastructure Pilot Program.

- Need. Support EV adoption while minimizing the impact of EV charging on the distribution grid; manage future EV charging load.
- Deployment Timeline. Offer rebates for the electrical infrastructure and upgrades at EV charging sites and rebates for the smart charging equipment that enables managed charging in Phase I; install four Company-owned fast charging stations.
- Alternatives Considered. Considered a "do nothing" scenario, as well as scenarios base on lower or higher EV adoption rates.
- Benefits. Energy and demand savings; fuel and maintenance savings for EV drivers; reduced greenhouse gas emissions.
- Phase III Request. None.
- Progress to Date. Issued rebates for 110 charging stations through November 30, 2022, with additional rebates to be issued pending installation and verification of selected charging stations; submitted permit for four Company-owned fast charging stations.

6. Security

Dominion Energy Virginia will continue to protect the distribution grid by providing adequate and cost-effective security control measures to manage the growing threat to the energy sector and to protect from cyber and physical attacks.

a. Physical Security

The Company plans to enhance physical security at key distribution substations.

- Need. Protect the distribution grid from security threats, thus protecting the Company and its customers.
- Deployment Timeline. Enhance physical security at 45 substations through completion of the GT Plan.
- Alternatives Considered. Considered not enhancing physical security at critical distribution substations; rejected alternative because it would leave these substations vulnerable to threats.
- Benefits. Improved detection, monitoring, and response time to potential security threats.
- Phase III Request. Enhance physical security at 18 critical distribution substations.
- Progress to Date. Enhanced physical security at three critical substations as of December 31, 2022. Near competition on seven additional substations.

b. Cyber Security

The Company plans to protect the investments proposed in the Grid Transformation Plan through the necessary cyber security investments.

- Need. Protect the distribution grid from security threats, thus protecting the Company and its customers.
- Deployment Timeline. As needed to protect other approved grid transformation projects.
- Alternatives Considered. Considered cyber security solutions as needed based on the security needs of the specific project, leveraging existing solutions where possible.
- Benefits. Avoided attacks on the system; mitigated risk of new or emerging threats.
- Phase III Request. Cyber security solutions as needed to protect other Phase III grid transformation projects.
- Progress to Date. Leveraged existing agreements and solutions, requiring limited cyber security improvements to support other GT Plan projects.

7. Telecommunications

Dominion Energy Virginia proposes to deploy a comprehensive telecommunications strategy requiring multiple components specifically designed and deployed as an integrated solution to meet the wide-range needs of a transformed distribution grid. The strategy includes Tier 1, a high-speed broadband with very low latency network with redundancy; and Tier 2, a broadband network with redundancy, as well as increasing the capacity of the Company's network operations center ("NOC"). This strategy also includes upgrading identified telecommunication sites and replacing network infrastructure within identified substations.

- Need. Enable the secure communication required for a transformed grid. Enhance security, reliability, and resiliency of data transport.
- Deployment Timeline. Tier 1 by 2021; Tier 2 deployed through completion of the GT Plan; NOC capacity increases through completion of the GT Plan; telecommunication site upgrades by 2026; substation network upgrades completion of the GT Plan.

- Alternatives Considered. Prior to Phase I, various alternatives considered to address the wide range of business and technical requirements. Now that deployment of Tier 1 and Tier 2 has begun, no alternatives considered.
- Benefits. Secure, reliable, and resilient telecommunications infrastructure; enabled grid transformation projects that require real-time communications for situational awareness and grid control.
- Phase III Request. Continue deployment of Tier 2 telecommunication solutions; upgrade 12 identified telecommunications sites; replace network infrastructure at 156 identified substations.
- Progress to Date. Completed Tier 1 implementation. Deployed Tier 2 telecommunications solutions to over 142 facilities, including laying 149 miles of fiber. Increased capacity of the NOC to accommodate Tier 1 and Tier 2 completed work.

8. Customer Education

Dominion Energy Virginia plans to improve the customer experience by incorporating education into various Plan components and including general energy education. Appendix D includes the full details of the customer education plan. While this customer education plan focuses on enhanced capabilities enabled by GT Plan, it supplements the Company's overall efforts to educate its customers on topics ranging from available rate schedules to general energy education.

- Need. Provide customers with concise, consistent, and easy-to-understand educational content.
- Deployment Timeline. As needed to support other approved grid transformation projects.
- Alternatives Considered. Considered various communication channels based on the educational need.
- Benefits. Improved customer experience; enhanced understanding of GT Plan and related benefits.
- Phase III Request. Customer education as needed to support other Phase III grid transformation projects.
- Progress to Date. Developed and published concise, consistent, and easy-to-understand content via multiple external communications channels.

C. Alignment with Customer and Stakeholder Feedback

As discussed in Section III.B, the Company received customer feedback on a range of priorities associated with the Grid Transformation Plan as part of the 2023 Maslansky Survey. Figure 4 notes the top findings on what customers rank with highest importance.

Figure 4: Customer Feedback Priorities

	Customer Priorities
1	Completes work without needing follow-up
2	Responds quickly to replace faulty equipment
3	Completes scheduled work when they say they will
4	Protects equipment from hazards and wear-and-tear that can result in unexpected outages
5	Invests in advanced technologies that help prevent outages or reduce their duration
6	Adapts effectively in the event of disruptions or crises
7	Has an outage map that includes accurate estimates of outage time and progress in restoring power
8	Invests in technology that helps prevent outages and respond to them faster when they occur
9	Increases energy availability by identifying the ideal locations for new facilities
10	Allows me to set custom alerts so I can choose which notifications I want to receive and how I want to receive them

As shown in Figure 4, among attributes tested, those relating to outage response and prevention rise to the top as priority areas of focus. These findings support the proposed GT Plan investments and make clear that they will provide the types of benefits the Company's customers value most—enhanced reliability and accurate information.

As discussed in Section III.C, the Company initiated a series of stakeholder sessions in 2019 to inform and develop goals for a modern grid and the customer experience. Through the 2019 GT Plan stakeholder process, four goals were identified: (i) enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access (Optionality); (ii) evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles (Sustainability); (iii) build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management (Resiliency); and (iv) deliver value for customers by optimizing demand and seeking to reduce system and customer costs (Affordability). GT Plan projects directly support each of these four goals, through deployment of technology to empower customers to make informed decisions about their energy usage, enabling increased adoption of DERs in a responsible manner, and delivering better reliability and fewer outages for customers.

D. Costs

The Company estimated costs for grid transformation projects using competitively-negotiated contracts and responses to competitive requests for proposals ("RFPs") and requests for information ("RFIs"), informed by prior experience. The Company's filing provides detailed information used to determine costs and includes the relevant contracts or summaries of the completed RFPs and RFIs.

In Phase I of the Grid Transformation Plan, the Company suggested, and the Commission approved, a maximum amount of investment—by project—deemed reasonable and prudent ("cost caps"). Should costs exceed the approved cost caps, those costs would be incurred at the Company's risk, and it would be the Company's burden to demonstrate reasonableness and prudence for any such incremental investment.

Figure 5 provides the cost caps for each component of the GT Plan. For Phases I and II, the cost caps shown are those approved by the Commission in the prudence determination proceeding or those approved or pending approval in a Rider GT proceeding. The amounts shown for Phase III represent the cost caps proposed by the Company, subject to further refinement during the course of the proceeding.

Figure 5: Phases I, II, and III Costs ($M)

Project	Phase I		Phase II		Phase III	
	Capital	O&M	Capital	O&M	Capital	O&M
AMI	---	---	$186.1	$12.2	$23.2	$23.2
CIP	$83.7	$27.0	$135.0	$68.9	$4.3	$0
Mainfeeder Hardening	$47.9	$0	---	---	$508.3	$0
Targeted Corridor Improvement	$0	$12.8	$0	$16.3	$0	$31.9
Voltage Island Mitigation	$6.7	$0	$11.4	$0	$25.3	$0
Intelligent Grid Devices	---	---	$29.1	$0.02	---	---
FLISR	---	---	$10.0	$0.9	---	---
OMS	---	---	---	---	$15.7	$1.0
DERMS	---	---	$5.2	$0	$8.2	$1.1
Hosting Capacity	$0.3	$0.05	---	---	---	---
EAMS	---	---	$18.8	$1.2	---	---
Voltage Optimization Enablement	---	---	$97.1	$0	$215.0	$0
Substation Technology Deployment	---	---	$32.1	$0	$144.1	$0
NWA Program	---	---	---	---	$0.1	$0.1
Locks Campus Microgrid	$12.3	$0.08	---	---	---	---
Physical Security	$9.4	$0	$37.3	$0.2	$71.0	$0
Transportation Electrification	$3.8	$16.2	---	---	---	---
Telecommunications	$53.0	$1.6	$97.9	$4.1	$83.0	$12.1
Cyber Security	$1.1	$0.4	$6.5	$2.8	$0.5	$0
Customer Education	$0	$2.7	$0	$3.0	$0	$1.1
Total*	**$211.5**	**$60.8**	**$666.5**	**$109.6**	**$1,098.7**	**$70.6**

*Totals may not add due to rounding

The Company has committed that the costs of the Plan associated with the deployment of AMI and the CIP in Phases I, II, and III will not be the subject of a rate adjustment clause petition. The Company received approval to recover costs related to the remaining Phase I projects through Rider GT. As to other phases of and projects in the Plan, the Company has not yet determined its plans for cost recovery.

E. Benefits

The overarching benefits of the Grid Transformation Plan are that it facilitates the integration of DERs and enhances distribution grid reliability and security. All proposed projects contribute to these core objectives in some way.

The Company engaged a third-party industry expert, West Monroe Partners, to generate a cost-benefit analysis ("CBA") model for the Grid Transformation Plan that quantifies the benefits of the GT Plan compared to the costs. Figure 6 presents the results of the CBA.

Figure 6: CBA Summary

GT Plan Cost-Benefit Model Summary

(Revenue Requirement Basis, $ in Millions)

BENEFITS & COSTS	NOMINAL	PV[1]
AMI-Centric Programs		
AMI, Time-of-Use Rate, and Peak-Time Rebate (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)*:	**$1,523.9**	**$650.9**
Avoided/Deferred Capital	$428.5	$104.7
O&M Savings	$575.3	$287.6
Energy & Demand Savings	$217.2	$104.8
Reduction of Bad Debt & Energy Diversion	$303.0	$153.8
COSTS *(Revenue Requirement)*:	**$978.2**	**$606.9**
Net Benefit (Cost):	**$545.8**	**$44.0**
Benefit/Cost Ratio:	**1.6**	**1.1**
Grid Infrastructure		
Mainfeeder Hardening, Targeted Corridor Improvement, and Voltage Island Mitigation (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)*:	**$4,311.1**	**$970.0**
Avoided/Deferred Capital	$73.8	$9.9
O&M Savings	$69.9	$20.9
Enhanced Reliability	$4,167.4	$939.2
COSTS *(Revenue Requirement)*:	**$2,399.8**	**$924.9**
Net Benefit (Cost):	**$1,911.3**	**$45.1**
Benefit/Cost Ratio:	**1.8**	**1.0**
Grid Technologies		
Intelligent Grid Devices, FLISR Software, OMS, DERMS, Hosting Capacity, EAMS, VO Enablement, Substation Technology Deployment, NWA Program, Locks Campus Microgrid, and Telecom (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)*:	**$9,963.5**	**$1,940.7**
Avoided/Deferred Capital	$926.9	$92.2
O&M Savings	$127.1	$68.0
Energy & Demand Savings	$3,393.4	$640.1
Enhanced Reliability	$5,516.1	$1,140.4
COSTS *(Revenue Requirement)*:	**$3,543.8**	**$1,397.1**
Net Benefit (Cost):	**$6,419.7**	**$543.6**
Benefit/Cost Ratio:	**2.8**	**1.4**
Transportation Electrification		
Customer EV Programs (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)*:	**$2,500.6**	**$309.4**
Avoided/Deferred Capital	$2,302.0	$248.9
Energy & Demand Savings	$198.6	$60.5
COSTS *(Revenue Requirement)*:	**$321.0**	**$111.3**
Net Benefit (Cost):	**$2,179.6**	**$198.1**
Benefit/Cost Ratio:	**7.8**	**2.8**
GT Plan Total[3]		
Total Net Benefit (Cost):	**$9,953.6**	**$294.8**
Total Benefit/Cost Ratio:	**2.2**	**1.08**

1Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 6.951%

[2] O&M Savings, Energy & Demand Savings, Enhanced Reliability, and Reduction of Bad Debt & Energy Diversion are stated on a Cash Flow Basis

[3] GT Plan Total includes costs and benefits associated with CIP, Customer Education, Physical Security, and Cyber Security costs not tied to specific projects

As can be seen, the CBA model represents a positive business case from a financial perspective, providing over $294.8 million in net benefits to customers on a net present value basis, with a benefit to cost ratio of 1.08. Additional quantitative benefits include reduced greenhouse gas emissions, increased EV ownership savings, and positive economic development impacts. Some of the benefits derive from programs and offerings that the Company will implement once the proposed projects are deployed, including a time-of-use rate and a peak time rebate program. Including these in the CBA model reflects the Company's commitment to these programs and offerings

The CBA model focuses on quantifiable benefits, but the Grid Transformation Plan produces other qualitative, non-quantifiable benefits. For example, there are benefits that are difficult to quantify, like avoiding a cyberattack; providing resilient service to military bases, hospitals and communities; and providing customers with accurate and timely information that has implications for their daily lives.

The following sections highlight certain GT Plan benefits important to the Company and various stakeholders.

1. Time-varying Rates

Transformational investments in AMI and the CIP, when coupled with customer education and communication, enable the Company to broadly offer time-varying rates. Time-varying rates provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and reduces the customers' bills. The Company has a concrete, definitive plan to implement time-varying rates on a system-wide basis—both a time-of-use rate and a peak-time rebate ("PTR") program. The Company has taken the initial steps outlined in its plan as presented in the 2021 GT Plan Document. Specifically, the Company launched its Off-Peak Plan—Schedule 1G—in January 2021. Schedule 1G was available to the first 10,000 customers who enrolled. While the Company estimated it would take four years to reach the enrollment cap, Schedule 1G reached 10,000 participants in less than one year on January 4, 2022. The Company recently filed for expansion of Schedule 1G to additional customers. In December 2022, the Company proposed a system-wide opt-in PTR program in its DSM proceeding, Case No. PUR-2022-00210. That case remains pending.

2. Demand-side Management Initiatives

The foundational and transformational investments proposed as part of the Grid Transformation Plan will enable enhanced and targeted DSM initiatives in many ways. Investment in the full deployment of AMI and the CIP will enable the Company to broadly offer enhanced demand response programs—such as time-varying rates, PTR, and managed charging for EVs—and to deploy new energy efficiency programs—such as voltage optimization. Additionally, the interval usage data captured by AMI will both enhance existing DSM programs and improve evaluation, measurement, and verification ("EM&V") of DSM programs. Finally, the deployment of DERMS will provide the capability to manage demand response programs going forward. All of these programs and enhancements should lead to savings for the individual customers who participate in the various DSM programs, but should also lead to system energy and demand savings that will benefit all customers. For example, voltage optimization utilizes the data collected from AMI and other intelligent grid devices to reduce the voltage supplied to customers to the optimum level, which results in lower energy consumption for most customers without a noticeable difference in service level.

3. Integrated Distribution Planning

As described in Section II, the fundamental changes in the energy industry have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs. The real-time data from AMI and intelligent grid devices, paired with automated control systems (*e.g.*, DERMS) and advanced planning tools have and will continue to be foundational to the transition to integrated distribution planning.

4. Reliability

Transformational investments in grid infrastructure and grid technologies will improve reliability for customers across the Company's service territory. While some projects, like mainfeeder hardening and voltage island mitigation, focus on targeted populations of customers, others will be deployed more broadly, such as targeted corridor improvement. The CBA model quantifies reliability benefits using the Department of Energy's Interruption Cost Estimate Calculator ("ICE Calculator"), a recognized method for determining the economic value of increased reliability. This tool has been updated multiple times over the past decade to improve the accuracy of the results, and the Company fully supports the quantified benefits presented. Additionally, Dominion Energy Virginia engaged with Lawrence Berkeley National Laboratory in 2020 on a multi-year project to refine the ICE Calculator and incorporate Virginia-specific data. Since 2020, updates to reliability survey questionnaires for residential and non-residential customers has been completed based on feedback provided by the Company and others involved in the initiative. In December 2022, a successful pre-test of the residential survey was conducted with a sample of Company customers. The survey of Company customers will be administered in the first half of 2023 until a statistically representative sample of Virginia-based customer feedback is collected. Lawrence Berkley National Laboratory plans to update the ICE Calculator with results from the first phase of survey activities by mid-2024.

5. Load Forecasting

The data obtained from AMI can also enhance the Company's load forecasting process. AMI data will permit the Company to examine consumption patterns on an hourly basis. This data can then be used to create consumption forecast models for various customer segment levels, for example, residential heating system type, electrification impacts, demand response and energy efficiency effects, and DER adoption. These feeder level forecasts can then be rolled up to a system level and compared against the Company's current forecasting methods.

6. Broadband Program

In addition to supporting grid transformation objectives, the foundational telecommunications investments proposed as part of the GT Plan also provide the opportunity to support expanded deployment of broadband in the Commonwealth through the Rural Broadband Program. The telecommunications project includes the extension of the Company's fiber network to substations and key facilities. The expansion of the Company's fiber network, particularly in rural unserved areas, provides opportunities to leverage the fiber network for the benefit of middle-mile expansion in unserved and underserved markets as a part of the Company's Rural Broadband Program. Not only does the fiber serve Dominion Energy Virginia's connectivity needs at key facilities, but it also supports existing and potential internet service providers' use of the fiber capacity to improve availability of broadband for commercial, government, institutional, and residential customers in unserved areas of Virginia. The Commission has approved rural broadband projects in Surry County, Botetourt County, Louisa County, Appomattox County, and in the Northern Neck region of Virginia.

F. Regulatory Process

The GTSA mandated that the Company petition the Commission for approval of a plan for electric distribution grid transformation projects. The GTSA also set forth the applicable standard for reviewing such petitions:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d.[7]

The Commission must rule on any petition not more than six months after the date of filing.

To date, the Company has submitted the following petitions for prudence determinations:

- In July 2018, the Company submitted its petition for approval of Phase I of the GT Plan in Case No. PUR-2018-00100. The Commission issued its final order in that proceeding on January 17, 2019.
- In September 2019, the Company submitted its second petition for approval of Phase I of the GT Plan in Case No. PUR-2019-00154. The Commission issued its final order in that proceeding on March 26, 2020 (the "2019 Final Order"), and its order on reconsideration on April 27, 2020.
- In June 2021, the Company submitted its petition for approval of Phase II of the GT Plan in Case No. PUR-2021-00127. The Commission issued its final order in that proceeding on January 7, 2022 (the "2021 Final Order").

[7] Va. Code § 56-585.1 A 6.

In addition to prudence determination proceedings, the Company has submitted two petitions for cost recovery of Phase I projects through a rate adjustment clause designated Rider GT:

- In August 2021, the Company submitted its petition for initial approval of Rider GT in Case No. PUR-2021-00083. The Commission issued its final order in that proceeding on May 13, 2022.
- In August 2022, the Company a petition to update Rider GT in Case No. PUR-2022-00140. That proceeding remains pending.

Figure 5 in Section IV.D provides a list of the GT Plan projects that the Commission approved in Phases I and II, along with the associated cost caps.

In the 2019 Final Order, the Commission ordered the Company to file an annual report on or before March 31, 2021, and each year thereafter, to include reporting metrics proposed by the Company and other information directed by the Commission. In its 2021 Final Order, the Commission added additional requirements for the annual report. The Company filed its first annual report on March 31, 2021, in the docket for Case No. PUR-2020-00154. The Company filed its second annual report on March 31, 2022, in the docket for Case Nos. PUR-2020-00154 and PUR-2021-00127. The Company filed its third annual report on March 31, 2023. The Company will incorporate additional metrics and information into its annual reports for any additional projects approved as part of Phase III.

LIST OF ACRONYMS

Acronym	Meaning
ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
AMR	Automated meter reading
BEA RIMS	Bureau of Economic Analysis Regional Input-Output Modeling System
BESS	Battery energy storage system
BTM	Behind-the-meter
CAIDI	Customer average interruption duration index
CBA	Cost-benefit analysis
CBMS	Customer Business Management System
C&I	Commercial and industrial
CI	Customer interruptions
CIP	Customer information platform
CIS	Customer information system
CMI	Customer minutes of interruption
COBOL	Common business-oriented language
DA	Distribution automation
DAS	Data analytics system
DCFC	Direct current fast charging
DERs	Distributed energy resources
DERMS	Distributed energy resource management system
DOE	Department of Energy
DR	Demand response
DSM	Demand-side management
EAB	Emerald ash borer
EAMS	Enterprise asset management system
EE	Energy efficiency
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EM&V	Evaluation, measurement, and verification
EPA	Environmental Protection Agency
EV	Electric vehicle
FAN	Field area network
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation and service restoration
GHG	Greenhouse gas
GIS	Geographic information system
GT Plan	Grid Transformation Plan
GTSA	Grid Transformation and Security Act of 2018
ICE Calculator	DOE's Interruption Cost Estimate Calculator
IDP	Integrated distribution planning
IEEE	Institute of Electrical and Electronics Engineers

Acronym	Meaning
IGDs	Intelligent grid devices
INSI	Itron Networked Solutions, Inc.
IT	Information technology
kV	Kilovolt
kWh	Kilowatt-hour
LTC	Load tap changer
MDMS	Meter data management system
MPLS	Multi-protocol label switching
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NIC	Network interface card
NIST	National Institute of Standards and Technology
NOC	Network Operations Center
NPV	Net present value
NREL	National Renewable Energy Laboratory
NWA	Non-wires alternatives
O&M	Operations and maintenance
OMS	Outage management system
OT	Operational technology
Phase I	Grid transformation projects for 2019, 2020, and 2021 approved in Case Nos. PUR-2018-00100 and PUR-2019-00154
Phase IA	Phase I projects approved in Case No. PUR-2018-00100
Phase IB	Phase I projects approved in Case No. PUR-2019-00154
Phase II	Grid transformation projects for 2022 and 2023 approved in Case No. PUR-2021-00127
Phase III	Grid transformation projects proposed generally for 2024, 2025, and 2026 in Case No. PUR-2023-00051
PII	Personal-identifying information
PTR	Peak-time rebate
RAC	Rate adjustment clause
RFI	Request for information
RFP	Request for proposals
RPS	Renewable energy portfolio standard
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCIP Program	Smart Charging Infrastructure Pilot Program
SONET	Synchronous optical networking
STATCOMs	Static compensators
SUP	Strategic Undergrounding Program

Acronym	Meaning
T&D	Transmission and distribution
TOU	Time-of-use
V	Volt
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act of 2020
VEJA	Virginia Environmental Justice Act
VO	Voltage optimization

GLOSSARY

ADMS (advanced distribution management system): A software platform that supports and manages the full suite of distribution grid management and optimization technologies employed by the Company.

AMI (advanced metering infrastructure): An over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

AMI head-end system: A back office system that receives and processes the data for smart meters, and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The AMI head-end system also provides information from smart meters to other Company operating and analytical systems.

AMR (automated meter reading): A technology that records usage data and transmits it to the Company one-way. The Company reads these meters through drive-by readings using specially equipped trucks that receive the data through radio signals.

Automated control systems: Technology that allows for near real-time adjustment of the grid to changing energy loads, distributed generation, or feeder fault conditions without or with limited operator intervention.

Backfeed: The flow of electric power from the distribution grid to the transmission grid. Also represents the flow of electric power from a net metering distributed energy resource to the distribution grid during periods where distributed generation exceeds consumption at the premises.

Backhaul network: The backhaul portion of the network comprises the intermediate links between the core network and the small subnetworks at the edge of the network.

Base rates: The Company's existing rates for generation and distribution services.

BESS (battery energy storage system): A type of energy storage that stores energy for later discharge to the electrical grid.

CBMS (customer business management system): The core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, rates and financial based activities.

CIP (customer information platform): A combination of technologies, applications, and projects at the core of the customer experience, consisting primarily of the CIS, MDMS, customer portals, and other customer experience applications.

CIS (Customer Information System): Another term for CBMS.

Collector: A device deployed as a component of AMI designed to enable two-way communications to and from meters within range of the device. The device captures meter data and transmits via a dedicated backhaul communications network to the AMI head-end system to drive business processes.

Cyber security: Programs, techniques, and technology to protect the networks, devices, and programs from cyberattack.

DCFC (direct current fast charging): Electric vehicle charging technology capable of charging batteries to a 60 to 80 mile range state of charge within 20 minutes.

Decentralization: A concept that involves moving the electric grid away from relying solely on large centralized generating plants that supply power via the transmission grid to the distribution grid and ultimately end users, to a power grid where large generating plants and smaller distributed energy resources supply the grid simultaneously from two directions: the large generators through transmission lines and the smaller resources supplying from the distribution grid.

DER (distributed energy resource): A broad term used to describe resources connected to the distribution system, many of which are generation resources using renewable energy, such as solar and wind. DERs can also include, but are not limited to, energy storage, EVs, and demand response assets.

DERMS (distributed energy resource management system): A system that monitors and analyzes performance and status data from multiple distributed energy resources and has the ability to control those resources to maintain safety and reliability on the energy grid while maximizing benefits of the resources.

Distribution grid: The portion of the electrical utility system that delivers electrical power from the transmission grid through a substation transformer to end-use customers; typical distribution grid operating voltages range from 4 kV to 46 kV.

DSM (demand-side management): Activities that are designed to modify the level and pattern of electricity usage. DSM efforts in the Commonwealth focus primarily on two methods to manage demand: (i) energy efficiency and conservation, which aims to reduce the total amount of electricity used; and (ii) demand response (often peak shaving), which aims to shift the time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices on the electric grid.

EAMS (enterprise asset management system): A system that aggregates data and attributes of grid assets and provides capabilities to manage grid assets at all points in their life cycle, including procurement, deployment, and retirement. The system allows for collection of information related to the health and performance of grid components and analysis to drive life cycle decision making.

EM&V (evaluation, measurement, and verification): The collection of methods and processes used to assess the performance of demand-side management activities so that planned results can be achieved with greater certainty and future activities can be more effective.

Fault: An abnormal electrical condition caused by a short circuit on a feeder section.

Feeder: An electric distribution subsystem that begins at a substation and distributes electrical power within a localized service area. Feeders are comprised of mainfeeders, tap lines, and service lines.

FLISR (fault location, isolation, and service restoration): A distribution network system that works with intelligent grid devices such as switches, reclosers, line sensors, and a secure communications network to automatically isolate faulted feeder sections and reroute power to restore most customers in a matter of seconds or minutes.

GIS (geographic information system): A system designed to capture, store, analyze, and present spatial or geographic data, herein referring to distribution grid assets.

Grid hardening: Physical grid improvements that improve reliability and resiliency by rebuilding portions of the grid to eliminate outages and reduce damage for faster restoration.

Grid modernization: A broad term used to describe efforts to improve and modernize the grid.

Grid transformation: A broad term used to describe efforts to improve and modernize the grid.

Hosting capacity: The estimated amount of DERs that can be connected to each segment of the distribution grid without causing voltage or loading issues as determined by engineering analysis.

IGDs (intelligent grid devices): Various devices that provide situational awareness and control capability of the grid and enable two-way communication and centralized control of the power system.

Integrated distribution planning: A consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid integration needs of the distribution grid.

Intermittent generation: Generation resources that do not produce continuously available electricity due to external factors that cannot be controlled, such as solar and wind power. The power from such resources is non-dispatchable, meaning that it cannot be called upon at all times, only at times when the conditions for their power are present (*e.g.*, sun or wind) and the amount of power varies depending on those conditions.

Kilovolt (kV): Unit of measure for electric equipment and facilities representing 1,000 volts.

Latency: The amount of time it takes for a packet of data to get from one designated point to another through telecommunications networks.

Mainfeeder: The three phase sections of a feeder that distribute electrical power from substations to tap lines and individual customers.

MDMS (meter data management system): A system that processes and stores interval data used for billing, and calculates billable consumption for interval meter data.

Mesh network: The information network created from smart meters communicating with each other.

Microgrid: A group of interconnected loads and DERs that act as a small power grid, able to operate when connected to the larger distribution grid and also able to continue to operate as an "island" when there is an interruption or other grid disturbance that affects normal power flow from the grid.

Microgrid controller: A device that enables the establishment of a microgrid by controlling distributed energy resources and loads in a predetermined electrical system to maintain acceptable frequency and voltage while the microgrid is disconnected from the distribution grid.

MPLS (multi-protocol label switching): A mechanism for the routing of communications within a network as data travels across network nodes.

One-way energy: Power flow from a centralized location, such as a substation, along a distribution feeder, to end users.

OMS (outage management system): A centralized software solution and associated infrastructure for the purpose of analyzing and managing outage events on the distribution system. It uses field information and notifications from customers to identify outage events, create and manage restoration work requests, and provide restoration information to customers.

PTR (peak-time rebate) programs: Programs that provide incentive rewards for customers who achieve a desired reduction in usage during specific timeframes on abnormally hot or cold days.

Physical security: The protection of people, property, and physical assets from actions and events that could cause damage or loss.

Redundancy: In telecommunications, a process through which additional or alternate instances of network devices, equipment, and communication mediums are installed within network infrastructure. It is a method for ensuring network availability in case of a network device or path failure and unavailability.

Reliability: The ability of the distribution system to deliver uninterrupted power service to customers.

Repeater: An electronic device that receives a signal and retransmits it. Repeaters are used to extend transmissions so that the signal can cover longer distances or be received on the other side of an obstruction.

Resiliency: The ability of the power grid to withstand outages and maintain service to customers and recover from outages to restore service to customers.

RFI (request for information): A business process whose purpose is to collect written information about the capabilities of various suppliers.

RFP (request for proposals): A competitive bidding process where vendors and contractors offer to provide a service, asset, or good for a certain cost.

SCADA (supervisory control and data acquisition): A computer system that monitors and provides control of distribution assets, primarily located at substations.

Security information event and management (SIEM): A system to provide analysis of collected security events and logs to identify and detect potential security incidents as well as support incident response.

Single-phase: A segment of a power system consisting of one primary voltage conductor and one neutral conductor.

Situational awareness: Real-time perception of the grid and its environment that allows operators to project future outcomes as well as deal with present events.

Smart inverter: Inverters have the basic inverter function of converting direct current to alternating current, but also have additional capabilities such as voltage regulation, frequency support, and ride through capabilities (*i.e.*, staying online during grid events).

Smart meter: Electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information as part of an AMI system.

Three-phase: A segment of a power system consisting of three primary voltage conductors and one neutral conductor.

Time-of-use rates: Rates that have pre-defined periods with tiered energy pricing that are generally aligned with the actual cost of producing electricity during those periods

Time-varying rates: Rates that provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and can reduce the customers' bills.

Transmission grid: The high voltage part of the electrical grid that carries bulk power directly from large generating facilities to the distribution grid. Typical transmission grid operating voltages range from 69 kV to 500 kV.

Visibility: Real-time awareness of the grid's operating conditions.

Voltage optimization: The more precise control of distribution grid voltage that is possible with information from smart meters and a voltage control system.

Voltage island: A single substation transformer that serves a population of customers without the support of available load transfer capability within the substation or adjacent feeders. If a single transformer fails, all customers served by the substation could face an extended outage.

APPENDIX LIST

A. Sponsoring Witness Chart

B. Existing Distribution Grid

C. 2023 Integrated Distribution Planning Roadmap

D. Customer Education Plan

Appendix A

Sponsoring Witness Chart

The listed witness sponsors the identified sections and appendices of the GT Plan Document.

Section/Appendix	Company Witness
Introduction	Wright
Executive Summary	Wright
I. Need for a Modern Distribution Grid	Wright
A. Context for Distribution Grid Transformation	Wright
B. Developments Supporting Grid Transformation – 2019 to 2021	Wright
C. Developments Supporting Grid Transformation – 2021 to 2023	Wright
D. DER Growth	Wright
E. Value of a Transformed Distribution Grid to Customers	Wright
II. Distribution Grid Planning	Johnson
III. Development of Grid Transformation Plan	Wright
A. Internal Process	Wright
B. Customer Engagement	Frost
C. Stakeholder Engagement	Wright
D. Environmental Justice Evaluation	Wright
IV. Grid Transformation Plan	Wright
A. Interrelated Nature of Projects	Wright
B. Projects	---
1. Advanced Metering Infrastructure	Stevens
2. Customer Information Platform	Jennings
3. Grid Infrastructure	---
a. Mainfeeder Hardening	Eisenrauch
b. Targeted Corridor Improvement	Johnson
c. Voltage Island Mitigation	Eisenrauch
4. Grid Technologies	---
a. Intelligent Grid Devices	Eisenrauch
b. FLISR	Eisenrauch
c. DER Management System	Stevens
d. Hosting Capacity Analysis	Johnson
e. Enterprise Asset Management System	Johnson
f. Outage Management System	Johnson
g. Voltage Optimization Enablement	Eisenrauch
h. Substation Technology Deployment	Johnson
i. NWA Program	Stevens
j. Locks Campus Microgrid	Stevens
5. Transportation Electrification	Frost
6. Security	---
a. Physical Security	Johnson
b. Cyber Security	Stevens
7. Telecommunications	Carroll
8. Customer Education	Frost

C. Alignment with Customer and Stakeholder Feedback	Wright
D. Costs	Wright
E. Benefits	Ludlow
1. Time-varying Rates	Frost
2. Demand-side Management Initiatives	Frost
3. Integrated Distribution Planning	Johnson
4. Reliability	Ludlow / Johnson
5. Load Forecasting	Johnson
6. Broadband Program	Carroll
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Existing Distribution Grid

As discussed in Section I.A of the Plan Document, the electric grid was originally designed for one-way flow of electricity to meet customers' demand—from the generator, through the transmission system, to the distribution system and the end-use customer. In the traditional distribution system design, electricity typically flows from a substation, through mainfeeders, to tap lines and then service lines that are connected to the end-use customer.

Dominion Energy Virginia's over 2.6 million customer accounts in the Commonwealth power the business economy and serve over 5 million residents. The Company's existing distribution system in Virginia consists of more than 53,000 miles of overhead and underground cable, and over 400 substations. The distribution system utilizes a variety of devices for functions from voltage control to power flow management, and relies on multiple operating systems for various functions from customer billing to outage management. The following sections provide a detailed description of the Company's existing distribution system.

A. Substations

The primary function of a distribution substation is to transfer power from the higher voltage system, which typically ranges from 35 kV to 230 kV on the Company's system, to the lower voltage system, which typically ranges from 4 kV to 35 kV. Once this power is "stepped down," it is placed on the distribution system for delivery to the end use customer.

There are many pieces of equipment and devices that help to facilitate this transfer of power, including the following:

Substation transformers. Equipment that handles the "stepping down" of higher voltages to lower voltages.

Substation bus. Metal tubes or bars that carry electric current from the substation transformer to other devices, such as circuit breakers, or from the other devices to the substation transformer.

Substation circuit breakers. Devices that enable the flow of power into and out of the substation and serve to isolate faults.

Voltage regulation devices. Devices that help keep voltage within the desired bandwidth.

Communication schemes and protocols. Communication hardware and software responsible for transferring data and signals from various devices within the substation, as well as between the substation and the operating center or engineers and technicians.

Relays. Decision-making devices that control the operation of various high voltage equipment such as circuit breakers.

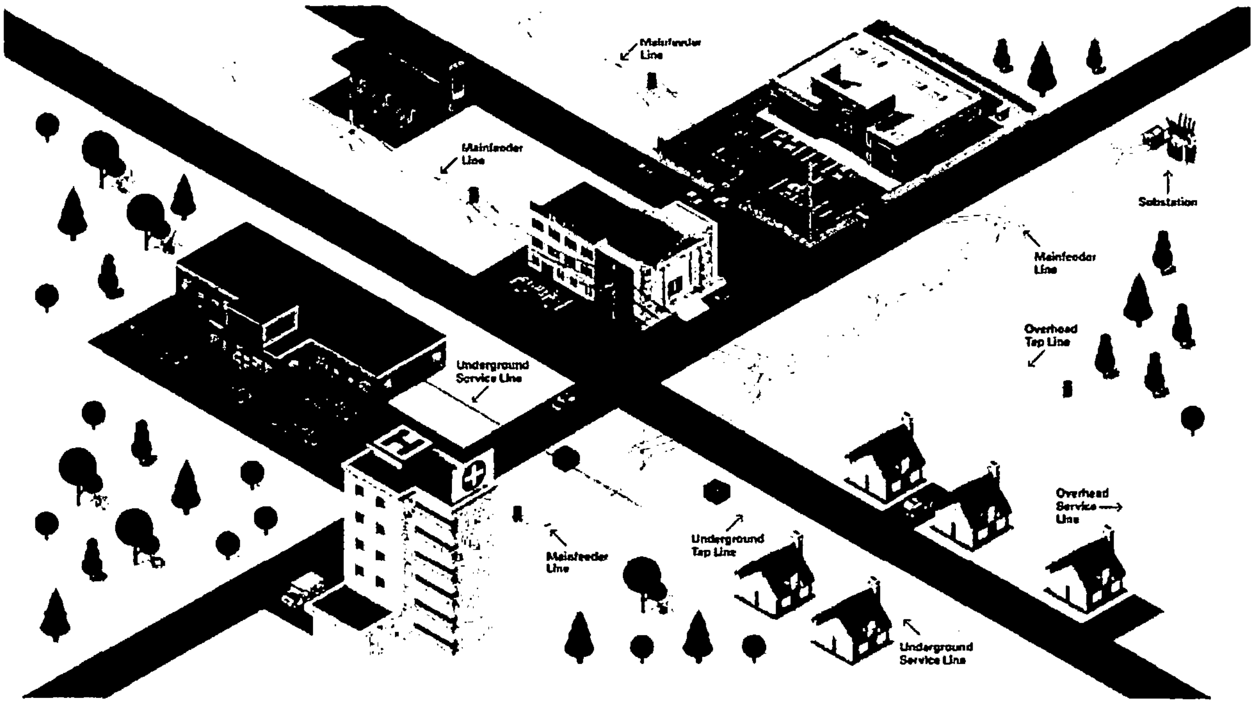
Electrical sensors. Devices responsible for providing electrical signals and inputs into the relays.

Control house. Enclosure that houses relays, communication hardware, back-up batteries, and other low voltage devices.

B. Wires

Within the distribution system, the wires—also known as conductors—transmit electricity from substations to end-use customers. A system of conductors is referred to as either a circuit or a feeder. The Company will generally use the term "feeder" in this proceeding. The Company operates approximately 1,900 feeders in Virginia. There are three parts to feeders, the mainfeeders, the tap lines, and the service lines.

Distribution System Illustration



1. Mainfeeders

Mainfeeders are the three-phase portion of the distribution system that carries electricity from substations to tap lines and end-use customers. Larger customers, such as certain businesses and public services, are often served directly from the mainfeeders. Mainfeeders on the Company's distribution system typically serve hundreds or thousands of customers along many miles of conductor. The Company's distribution system in its Virginia service territory has approximately 12,000 miles of overhead mainfeeders and 1,900 miles of underground mainfeeders on its approximately 1,900 feeders.

2. Tap Lines

Tap lines are the portion of the distribution system that carry electricity from the mainfeeders to neighborhoods and individual end-use customers. The Company's distribution system in its Virginia service territory includes approximately 19,000 miles of overhead tap lines and approximately 25,000 miles of underground tap lines.

Separate from, but complementary to, the Grid Transformation Plan is the Company's Strategic Undergrounding Program ("SUP"). This program focuses on undergrounding *tap* lines to decrease downed wires and work repair locations, enabling crew redeployment to other outage locations and allowing a faster recovery after severe weather events. In contrast, the focus of grid transformation efforts is largely on the *mainfeeder* portion of the distribution system.

3. Service Lines

Service lines are the low voltage portion of the distribution grid that carries electricity from service transformers to customers. For residential customers, the most common service voltage is 120/240 volt ("V"), meaning appliances and devices using electricity can be connected to either a 120V or a 240V outlet from customers' electrical panels. Commercial and industrial service transformers deliver a variety of service voltages, including 120/208V, 120/240V, and 277/480V. Service lines typically connect to the service transformer on one end and the meter on the other end. In some instances, one service line can be used to serve multiple customers by connecting additional service lines to it along the route from the transformer to the meter.

C. Devices

There are devices installed along the feeders that facilitate the safe and reliable distribution of electricity, including the following:

Voltage control devices. Voltage control devices are used to manage grid voltage to ensure customers receive adequate voltage at the meter. The most common voltage control devices on the distribution grid are voltage regulators and capacitors. Voltage regulators monitor and adjust the voltage at the substation or along the feeder based on control programming that is loaded by Company engineers. The programming typically uses loading and specific electrical information based on the location of the equipment. Capacitors are used to manage power flow efficiency on the distribution grid. As customers use electricity, the equipment along the grid that delivers the power, such as transformers and conductors, consume additional electricity and cause electrical losses to occur, causing voltage to decrease. Capacitors are used to provide a portion of that additional electricity and reduce the losses, which in turn improves voltage.

Stepdown transformers. Stepdown transformers change the voltage level on the distribution wires from a more predominant distribution voltage, such as 35 kV as found at many of the Company's substations, to a less common distribution voltage, such as 6 kV or 4 kV.

Service transformers. Service transformers connect to the grid and serve to lower the voltage from distribution voltages used on the mainfeeders and tap lines, typically 4 kV to 35 kV, to the service voltage used by customers. The Company has approximately 600,000 service transformers in Virginia.

Protection and control equipment. Protection devices perform several different functions on the distribution grid, including monitoring power flows and voltages, providing switching points to reconfigure power flows, automatically disconnecting a grid segment when a problem is detected, and providing the associated communications functions to allow protection activities to occur. Electronically controlled line devices, fuses, line sensors, relays, and communications gateways are examples of protection and control equipment.

- *Electronically-controlled line reclosers*. Devices that can sense grid problems and take action to de-energize and isolate line sections where necessary, and that can also receive control commands from the advanced distribution management system ("ADMS") using a secure telecommunications network.
- *Line sensors*. Devices installed at select locations along the feeder that provide situational awareness regarding normal loading and voltage, as well as fault related information that can be used by the ADMS to further narrow potential outage locations.
- *Digital relays*. Devices that provide advanced protection and control functionality, and detailed grid performance information including near real-time situational awareness about grid operation.
- *Communication gateways*. Devices that facilitate secure communications and function as a central data hub, sending and receiving all data and control functionality between substations and the ADMS.

D. Meters

Dominion Energy Virginia customers primarily have one of three types of meters: smart (*i.e.*, AMI) meters, automated meter reading ("AMR") meters, or manually read meters. As of December 31, 2022, approximately 24% of Virginia customer meters are AMR meters, approximately 74% are smart meters, and approximately 2% are manually read meters.

AMR Meters. The Company began deploying AMR meters throughout the service territory over 20 years ago. Usage data from AMR meters is collected through drive-by readings once a month. Specially equipped trucks used to drive throughout the service territory daily, covering approximately 400 different meter route cycles throughout each month. The Company used meter readers to drive these routes. The equipment collects a meter reading from the AMR meters within range, which the Company then uses for monthly billing. AMR meters cannot be remotely controlled or operated, meaning that the Company must send a field representative for common requests like connecting or disconnecting service. The Company utilized meter servicers to execute these and other requests.

Smart Meters. Smart meters are electric meters that enable two-way communications, digitally gathering energy usage data in specified increments (*i.e.*, interval data) and other related information several times a day. Smart meters are equipped with a network interface card and communicate with each other, creating what is referred to as a mesh network. A system of field telecommunications devices—comprised of devices called repeaters and collectors—gathers meter data from the mesh network and transmits the data gathered back to the utility through a backhaul network. Together, the mesh and backhaul networks are called the field area network. A back office system, also called a head-end system, receives and processes the data and serves as an operating platform for the back office team responsible for operation and maintenance. The term AMI, or "advanced metering infrastructure," refers to the over-arching metering system, which includes smart meters, a field area network, and a back office system.

In 2008, the Company began to deploy AMI in a targeted fashion based on specific operational and customer needs. Taking a measured pace over the course of several years, the Company continued to deploy smart meters in larger quantities and densities in diverse geographical areas of the service territory to validate deployment and operational strategies. The Company used the knowledge gained from this initial deployment of AMI to develop its strategy for full deployment across the service territory. As of December 31, 2022, the Company currently has approximately 1,950,990 smart meters deployed across its service territory.

Manually Read Meters. As of December 31, 2022, approximately 59,395 customers have manually read meters, primarily to gather energy usage data in specified increments (*i.e.*, interval data) or monthly peak energy demand. To obtain this data, meter readers visit the customer premises and must walk up to the meter to record energy usage via an electronic "probe" approximately once per month. The meter readers that drive the AMR routes also complete these visits. The Company has deployed manually read meters to support offering time-varying rates to commercial and industrial customers that do not have smart meters. The Company has also deployed manually read meters to provide additional information to net metering customers that do not have smart meters. Finally, the Company has deployed manually read meters for the limited number of customers that have opted out of the Company's smart meter deployment.

E. Operating Systems

1. Customer Experience Systems

Customer Information System ("CIS"). Deployed about 23 years ago, the CIS is the core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, and rates and financial based activities. The CIS is an employee-facing system, and is also referred to internally as customer business management system ("CBMS").

CBMS is built on a mainframe platform using the programming language COBOL. Users use what is referred to as a "green screen" to view information. The system lacks a logical workflow, requiring users to memorize a series of four letter commands to navigate through screens. The system is not Windows based; nor is it compatible with using a mouse or cursor for simple navigation. The vendor no longer supports the system, and service providers do not routinely hire or train COBOL programmers. The limited services that are available for CBMS come at an increasingly higher cost.

Manage Accounts. Deployed in 2003, Manage Accounts is the customer-facing web self-service platform for residential and small commercial customers.

Key Customer. Deployed in 2006, Key Customer is the customer-facing web self-service system for large customers that are assigned an account representative.

Property Manager Portal. Deployed in 2013, the Property Manager Portal is the customer-facing web self-service tool for property management companies to manage landlord agreements and turn on / turn off service for their properties.

Agency Web Access ("AWA"). Deployed in 2006, Agency Web Access is the customer-facing web self-service application for charities and third-party agencies (*e.g.*, Salvation Army) to make energy assistance payments on behalf of customers.

Meter Data Management System ("MDMS"). Deployed in 2009, the meter data management system is the employee-facing system that processes and stores interval data used for billing and calculates billable consumption for interval meter data.

Gateway. Deployed in 2013, Gateway is the employee-facing web-based front end system to CBMS and other systems used in the contact center. Gateway is the primary tool for customer service representatives to interact with customers.

Knowledge. Deployed in 2016, Knowledge is the employee-facing system that allows for systematically capturing, describing, organizing, and sharing information including alerts, work processes, and policies across customer service.

E-Gain. Deployed in 2010, E-Gain is the employee-facing system that imports and sorts emails and work tickets, creating a queue for response. E-Gain includes auto replies and templates for responses.

LanBill. Deployed in 1996, LanBill is the employee-facing system that allows back office personnel to manually edit and print bills flagged for special handling. LanBill is used to process large complex bills that are not fully automated in CBMS.

Bill Image. Deployed in 2003, Bill Image is the employee-facing software used to render an image of the bill on demand in Manage Account and Gateway.

Agiloft. Deployed in 2011, Agiloft is the employee-facing record keeping system used to track elevated customer issues and inquiries.

Demand-side Application ("DSA"): DSA is the employee-facing system used to track inventory and initiate service orders for water heater controls.

State and Local Taxes ("SLT"). SLT is a mainframe application that aggregates taxes at a jurisdictional level for reporting and remittance.

2. Grid Operation Systems

AMI and AMR head-end systems. The system that receives and processes the data and serves as an operating platform for the back office team responsible for operating and maintaining AMI and AMR, respectively.

Advanced distribution management system ("ADMS"). A software platform that supports a full range of distribution management and optimization tools, such as supervisory control and data acquisition ("SCADA"). The Company implemented the first phase of ADMS in 2019, which provides the basic data acquisition and control functionality. The second phase of ADMS includes building the functionality for fault location, isolation, and service restoration ("FLISR"), a centralized system that leverages an operational model and SCADA to automate fault isolation and reduce the number of customers affected.

Outage management system ("OMS"). A system that provides tools and information to efficiently restore power to customers by providing outage analysis and prediction functionality. The system enhances public and worker safety, and serves as the Company's system of record for outage history. The existing OMS was deployed in 1994. The third phase of ADMS includes an OMS replacement that will leverage the real-time operational model from ADMS for improved outage tracking and modernized functionality.

Data analytics system ("DAS"). A system that stores and quickly processes large amounts of data to create advanced analytics solutions. The existing DAS was deployed in 2017.

F. Telecommunications

Dominion Energy Virginia currently has a telecommunications ("telecom") transport portfolio that consists of Company-owned fiber, leased lines, copper cables, microwave, and public carrier solutions. The Company has a network operations center ("NOC") that is responsible for provisioning, testing, monitoring, troubleshooting, and dispatching the Company's telecommunication network year-round.

G. Security

The existing distribution system is protected by a comprehensive security program designed to provide risk-informed, adequate, and cost-effective security control measures that manage the growing threat to the energy sector and protect the Company, its assets, and its customers from cyber and physical attacks. The Company's security program has been subjected to internally conducted and third-party vulnerability assessments and penetration tests (announced and unannounced); peer reviews; and internal and external audits. Results from those engagements inform the Company's continuous improvements to both cyber and physical security.

H. Electric Vehicle Infrastructure

EVs are typically charged by plugging the EV into a charger that is connected to the electric grid. There are three major categories of chargers that are distinguishable by the amount of power the charger can provide, which results in different speeds of charging:

- Level 1 refers to use of a standard 120V outlet, which charges three to five miles of range per hour. Level 1 charging is ideal for overnight charging for EV owners that travel about 30 miles or fewer per day.
- Level 2 chargers require a higher voltage at 240V, which charges 10 to 20 miles of range per hour. Level 2 charging is ideal for workplaces, multi-family dwellings, and locations with the potential for more electric vehicles than chargers.
- Level 3—also known as direct current fast charging ("DC Fast Charge" or "DCFC")—can charge an EV battery to approximately 80% of capacity in 20 to 30 minutes. DCFC requires three-phase electric service and significant capacity. It is ideal for public locations to support travel over long distances.

As of December 31,2022, there were approximately 1,000 Level 2 (*i.e.*, 240V) and DCFC charging station locations in Virginia available for public use. However, not all of these stations are available to all EV drivers, and some are only available during limited hours.

Integrated Distribution Planning Roadmap

Dominion Energy Virginia (or the "Company") defines integrated distribution planning ("IDP") as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resource ("DER") integration needs of the distribution grid. In 2019, the Company presented a white paper regarding its preliminary plans to transition to an IDP approach (the "2019 White Paper"). Transitioning from traditional distribution planning processes to IDP is an industry-wide effort as the electric power system continues its fundamental shift from a world of centralized large-scale generation and a one-way power flow to the evolving paradigm of all type and number of DERs and a dynamic system with bidirectional and constantly changing power flows. The traditional distribution grid was not engineered and built for this evolving purpose. Consequently, the Company has actively engaged in IDP efforts and will continue to do so as IDP concepts further mature and evolve over the next decade and beyond.

This IDP roadmap provides an overview of the Company's efforts and successes thus far to transition to IDP and establishes tangible goals and timeframes as the Company's distribution planning processes shift toward IDP.

I. Background on Company IDP Efforts

In 2019, Dominion Energy Virginia presented the 2019 White Paper to provide a conceptual first look at its transition toward IDP.[1] The 2019 White Paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are integrated into the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including:

- Centralization of the Company's organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments;
- Development of an initial forecast of DERs by feeder;
- Publication of three hosting capacity tools, one that allows customers and developers to see the sections of the distribution system that may be more suitable to site new clean energy installations, one that reflects the ability to interconnect behind the meter DER to the distribution grid, and one that provides available hosting capacity for transportation electrification.

[1] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2019-00154, Petition, Exhibit 1 (filed Sept. 30, 2019).

- Installation of two battery energy storage systems ("BESS") to study future non-wires alternatives;
- Continued construction of a microgrid to study future non-wires alternatives;
- Installation of advanced metering infrastructure ("AMI") across 71% of its distribution system, enabling the collection of premise-level load and voltage data;
- Initial installation of intelligent grid devices on selected feeders, enabling the collection of operational data that improves the accuracy of engineering models;
- Substation technology deployments that not only add enhanced situational awareness and increased system operability but provide increasingly granular data that refines the accuracy of the Company's engineering models.
- Initiated implementation of a DER management system ("DERMS"); and
- Participation in numerous research and development projects with EPRI and other industry entities focused on modernizing distribution grid planning, using automated processes and tools and data driven techniques to improve model data quality and further IDP goals and objectives.

The Company also engaged with Quanta Technology, LLC ("Quanta") to solidify the conceptual framework through which the Company views the components of IDP.

II. IDP Roadmap and Implementation Timeline

The Company indicated its intention to present in 2023 a roadmap for IDP that adds tangible goals and timeframes to IDP maturity. Figure 1 provides the Company's current roadmap for IDP (the "2023 IDP Roadmap" or the "Roadmap"). The 2023 IDP Roadmap shows the IDP-related capabilities which the Company intends to focus on over the next five years, the goal associated with each of those capabilities, and an estimated timeframe. The IDP concept is not static, and further changes are expected in the next decade, as the Roadmap is based on the information known by the Company at this time. The Roadmap gives higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements while balancing the resources (*e.g.*, personnel, funds) required to implement these components and the interdependencies among many of the components.

Figure 1: 2023 IDP Roadmap

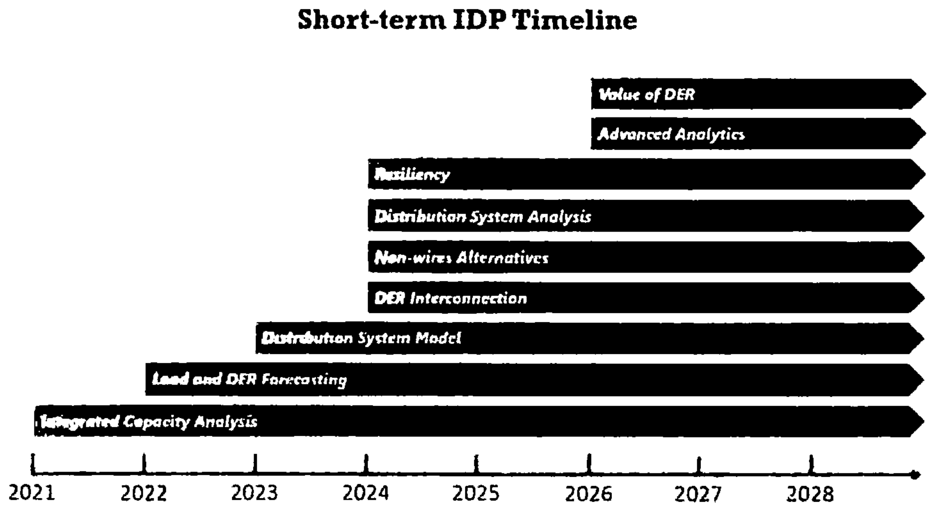
IDP Component	Goal(s)	Estimated Timeframe
Integrated Capacity Analysis	- Develop static DER hosting capacity analysis for public viewing - Develop static electric transportation hosting capacity analysis for public viewing - Develop methodology to increase hosting capacity - Develop methodology to calculate dynamic hosting capacity - Develop methodology to estimate firm capacity contribution from variable DER	2021 to 2022 Begin in 2024 2025 – 2028 2025 - 2028
Comprehensive Distribution Grid Load and DER Forecasting	- Conduct competitive solicitation process for new forecasting software - Produce hourly (8760) forecasting on all feeders, including forecasts of load and DER	2022 to 2024
Distribution System Model	- Enhance the existing engineering model to reflect the low voltage system - Continue to improve the data quality and comprehensiveness of the engineering model	2023 Ongoing
DER Interconnection	- Develop software that can perform automated time series simulations for interconnection impact studies for utility-scale DERs	Begin in 2024
Non-wires Alternatives	- Assess load areas with anticipated capacity needs for use in the proposed NWA Program by leveraging EPRI's ADAPT engineering software	Begin in 2024
Distribution System Analysis	- Develop software that can perform automated detailed modeling for distribution planning studies - Develop software that can perform automated simulations for interconnection impact studies for utility-scale DERs - Develop software that can perform automated detailed modeling for selected engineering studies	Begin in 2024
Resiliency	- Engage with industry leaders (e.g., IEEE, EPRI) to develop standard	2024 - 2028

IDP Component	Goal(s)	Estimated Timeframe
	metrics for measuring and assessing grid resiliency	
Advanced Analytics	- Identify and define advanced analytics use cases and applications supporting IDP - Define data requirements for advanced analytics applications to IDP - Develop and implement advanced analytics pilot project(s)	2026 - 2028
Value of DER	- Develop a methodology to calculate the location value of DER for specific value streams of interest	2026 - 2027

As can be seen in Figure 1, the next step in the evolution toward IDP requires a fundamental shift in software solutions to those that can be scaled to meet the computational requirements of the advanced analyses required of a modern distribution grid. This will include investments in and adoption of innovative technologies (*e.g.*, cloud computing, big data platforms) as well as the Company's continued engagement with research entities to develop these solutions. It will also require increased staffing in multiple disciplines (*e.g.*, engineering, economics, data science) to implement the solutions and processes. These requirements are not unique to the Company but are recognized as necessary by distribution grid planning organizations throughout the industry.

In the 2019 White Paper, the Company published a figure showing the evolution of IDP over time as enabling technologies are deployed throughout the Grid Transformation Plan. While the components shown on that maturity curve remain key components to the IDP framework that the Company envisions, the Company has produced an implementation timeline (Figure 2) to align with the IDP Roadmap, lessons learned from its efforts over the past several years, and its engagement with EPRI and other industry activities.

Figure 2: IDP Timeline (2023)



The IDP Roadmap and implementation plans will set the foundation for achieving the Company's IDP vision. However, attaining that goal is expected to require more than 5 years, partly because some of these areas are still emerging and are expected to continue evolving within and beyond this timeframe; implementation plans therefore may need to be adjusted accordingly. Additionally, some of these components are necessarily projected in later years since regulatory and policy drivers, as well as commercial solutions, are either absent, incipient, or still being developed.

Customer Education Plan, 2023 Update

In 2019, Dominion Energy Virginia presented its plan to support the projects proposed as part of its Grid Transformation Plan with customer education. The goal of this customer education plan was—and is—to educate customers about their energy consumption and how to manage their costs, empower customers to take advantage of the numerous enhanced capabilities enabled by the GT Plan, and educate customers on the benefits of grid transformation projects and their impact on reliability.

During Phase I of the GT Plan, the Company developed concise, consistent, and easy-to-understand content via multiple external communications channels, including but not limited to website pages, social media, digital and direct mail, bill inserts, presentations and public webinars, videos, and engagement with the customer service organization. In Phase II of the Grid Transformation Plan, the Company continued investments in customer education as needed to support other approved Phase II grid transformation projects. For example, foundational educational materials such as the web page and GT Plan video were updated to reflect Phase II priorities. See Attachment 1 for a sampling of the educational tactics deployed during Phases I & II.

Customer education for Phase III will continue to build on the customer education plan developed during Phases I and II. With many of the projects proposed in the Grid Transformation Plan now in the implementation phase, the Company is increasingly focused on direct customer outreach on individual projects as well as foundational education on the GT Plan overall.

Phase III Customer Education

The Company's continued implementation of the customer education approach and plan during GT Plan Phase III will endeavor to improve the customer experience. The Company strives to ensure outreach is efficient and effective in achieving the goals of educating customers, keeping them informed, and empowering them to take advantage of the numerous enhanced customer capabilities provided by the GT Plan.

During Phase III, and consistent with Phases I and II, the Company will focus on the following core categories:

Foundational Education

During Phases I & II, materials were developed to educate customers on the GT Plan projects and how their interdependencies work together to provide value and benefits to customers. Communication materials will continue to be updated regarding the need and benefits for the overall GT Plan and how the individual projects complement each other and work together to deliver benefits. Education of the overall GT Plan is important to provide context for why the Company is investing in individual projects—such as smart meters and intelligent grid devices—and how they drive enhanced reliability, provide opportunities for bill savings, and improve the customer experience.

In Phase III, the Dominion Energy website will continue to be updated as the main hub for public education. Videos, factsheets, and other foundational education materials are located on the "grid transformation" webpage, DominonEnergy.com/GTPlan, and will continue to be improved and modified. For example, the "vanity URL" for the GT Plan site was changed from dominionenergy.com/smartenergy to dominionenergy.com/gtplan to better align with other educational materials and provide consistency in naming.

Individual project websites are also a key tool in providing education and updates to customers. For example, our grid improvement projects site is regularly updated to provide the latest details on current, upcoming, and completed projects. Sites like this contain details on projects and can be linked on direct communication pieces like postcards or emails so that customers can find the latest information.

Smart Meters

The Company continues to deploy AMI throughout its service area and leverage the opportunity to interact with its customers. As we continue our smart meter deployment into Phase III, the smart meter deployment team will continue to execute an outreach and education strategy to ensure that the customer experience associated with the installation of smart meters is a positive one. This outreach will include targeted communications to each customer prior to and during the deployment phase of the new smart meters, including postcards, door hangers, and updated factsheets, brochures, and videos. These customer communications will alert customers of the upcoming meter exchange, direct customers to the website for frequently asked questions ("FAQs") and provide options for setting an appointment for property access, if needed. These communications will also serve as a mechanism to educate and inform customers on the capabilities resulting from the smart meter installation.

The Company plans to complete the majority of its smart meter deployment in 2024. As the deployment wraps up, customer education for smart meters will transition to focus on the advantages and enhanced capabilities of smart meters, now and in the future. Messaging will focus on improved customer experiences such as remote connect / disconnect of service and instructions on how to access energy usage data. Over time, the Company will further educate customers on additional capabilities as they become available.

Customer Information Platform ("CIP") Support

The Company plans to launch its CIP Core Project in April 2023. The implementation of the CIP is foundational to enhancing the customer experience. In support of the launch, the Company will provide customers with the knowledge to access and effectively use the new tools to save them time and money as each functionality is implemented. The Company's education approach will consist of multi-channel engagement including, but not limited to, website content, direct digital (text, emails, and push notifications), and bill inserts. The Company will implement a similar education approach with the Company's bill redesign project targeted for completion in 2024.

Customer Energy Management Programs

Building on the Company's smart meter deployment and CIP launch, customers will have access to more information about their energy usage and tools to help them save energy and money. In a separate proceeding, the Company has proposed to expand the Off-Peak Plan to allow more customers to take advantage of time-varying rates. The Company also seeks to expand offerings in its demand-side management ("DSM") portfolio—through programs such as peak-time rebates, EV telematics, and home energy reports—that will leverage the functionalities of AMI to enable these types of programs for residential customers. Customer education will focus on encouraging customers to voluntarily participate in these programs and empower them to make decisions and monitor their success.

Separate from the GT Plan, the Company has partnered with an experienced marketing firm, West Cary Group, to develop and execute an overarching and comprehensive DSM portfolio marketing and outreach strategy, to expand participation in DSM programs and improve the overall customer experience. That initiative is complementary to encouraging customer education on our customer energy management programs.

Grid Improvement Projects

While customers welcome reliability improvements, Dominion Energy Virginia recognizes that any work conducted in the field has the potential to impact the communities we serve; so, it is important to educate customers before, during, and after project completion.

Customer education for Phase III will continue to focus on direct customer education on projects such as mainfeeder hardening, voltage optimization enablement, and targeted corridor improvement. Communications will continue to be delivered through several channels including print materials, web, digital, and public presentations where appropriate.

Summary of Communications Tactics, GT Plan Phases I & II

	Communication Tactic
Foundational Education	• **Direct communications:** Factsheets, targeted customer emails • **Digital impressions:** Website updates, including "Energy 101" web page, "GT Plan" web page, ways to save on your bill, Grid Transformation Plan overview video & Phase II video
Customer Energy Management Programs	• **Customers:** New website, time-of-use graphic, explainer video, social media engagement, emails to eligible customers, launched bill comparison tool, rate comparison chart, comprehensive FAQs, energy-saving tips • **Stakeholders:** Webinars, factsheet, print collateral to support stakeholder engagement and their work in the community (*e.g.*, solar, EV owners, DSM stakeholders)
Transportation Electrification Support	• **Smart Charging Infrastructure Pilot:** website, webinars, virtual meetings • **General EV Education:** ChooseEV website with comparison calculators and public charging locator map, FAQs, new video, factsheet, reference guides, and customer events
Grid Improvement Projects to Enhance Reliability	• **Grid Infrastructure:** web page, FAQs, postcards, letters • **Hosting Capacity Tool:** press release announcing launch, outreach to stakeholders • **Corridor Improvements:** revised web page, Spanish translation of web content, revised letters, new postcards, bill inserts, media engagement • **DERMS:** press release announcing selection of a vendor for DERMS project
AMI rollout	• Factsheets, website updates, maps, comprehensive FAQs